Public Interest Energy Research (PIER) Program

FINAL PROJECT REPORT

DEFINING THE PATHWAY TO THE CALIFORNIA SMART GRID OF 2020 FOR PUBLICLY OWNED UTILITIES

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PREFACE

The California Energy Commission Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

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- Renewable Energy Technologies
- Transportation

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ABSTRACT

California's publicly owned utilities (POUs) are essential providers of electricity, water and natural gas to consumers. Because these utilities are governed by their locally elected officials, their first priority is to reflect the interests and concerns of the communities they serve. Like other utility service providers, local utilities must manage a myriad of complex challenges to meet the State's policy objectives including reducing greenhouse gas emissions, increasing the use of renewable energy, and relying first on energy efficiency, conservation and demand response to meet increases in energy demand. The evolution of smart grid technologies could help local utilities to address these issues while meeting their commitments to being low-cost, reliable, safe, and environmentally sound service providers. This research examines the efforts of 13 of the state's 40 local utilities to address the Smart Grid of 2020. Included are discussions of current plans, future visions, and recommendations for further research to investigate the potential benefits of smart grid technologies from the POU perspective.

Keywords: Advanced metering infrastructure, cyber security, energy policy, demand response, distributed generation, distribution automation, smart grid, substation automation, publicly owned utilities

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EXECUTIVE SUMMARY

This research report provides insight into the unique perspective shared among California's customer-owned public utilities (POUs) regarding the deployment of smart grid technologies, whether and how it can help meet state energy policy objectives. To investigate this issue, several key questions are examined:

1) How does the deployment of smart grid technology help a POU achieve state energy policy objectives?
2) How are POUs deploying smart grid technologies today?
3) What is the vision of the 2020 Smart Grid from the perspective of POUs?
4) What are the challenges that POU's face in implementing smart grid technologies?
5) How can the California Energy Commission apply its research to help POUs address these challenges?

California has a broad range of energy policy objectives that affect the customer-owners of POUs. The overarching objective of California's energy policy is to reduce the use of fossil-based fuels that, when consumed in producing electricity, generate greenhouse gasses (GHG) that are emitted into the atmosphere. These policies and related regulations and legislation direct utilities to:

- Reduce energy use by increasing energy efficiency in customer premises and in the grid.
- Reduce the use of fossil-fueled energy sources by increasing the use of clean, renewable energy resources.
- Motivate, and in some instances require, consumers to reduce energy use during peak consumption periods when energy is most scarce, is most expensive to produce and deliver, and is generated by the least efficient, highest-GHG emitting sources. Provide efficient, reliable, secure, and resilient transmission and distribution grids.

In 2007, the federal government enacted the Energy Independence and Security Act of 2007, Title XIII of which lays the foundation for current interpretations of smart grid terminology. In Title XIII, a national smart grid policy is enacted to support the modernization of the nation's electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet future demand growth and to achieve each of the following, which together characterize a smart grid:

(1) Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid.

(2) Dynamic optimization of grid operations and resources, with full cyber security.

(3) Deployment and integration of distributed resources and generation, including renewable resources.

(4) Development and incorporation of demand response, demand-side resources, and energy-efficient resources.

(5) Deployment of ''smart'' technologies (real-time, automated, interactive technologies that improve the operation of appliances and consumer devices) for metering, communications concerning grid operations and status, and distribution automation.

(6) Integration of ''smart'' appliances and consumer devices.

(7) Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air conditioning.

(8) Provision to consumers of timely information and control options.

(9) Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid.

(10) Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services.

The American Recovery and Reinvestment Act of 2009 (Recovery Act or ARRA) provides the U.S. Department of Energy (DOE) with about $4.5 billion to modernize the electric power grid and to implement Title XIII of the Energy Independence and Security Act of 2007 (EISA), which focused on the smart grid. The two largest initiatives are the Smart Grid Investment Grant (SGIG) program and the Smart Grid Demonstration Program (SGDP). SGIG focuses on deploying existing smart grid technologies, tools, and techniques to improve grid performance. SGDP explores advanced smart grid and energy storage systems and evaluates performance for future applications. California's POUs received federal stimulus grants of $321 million toward total program costs of $558 million. These smart grid investments equate to about $240 per each of the 2.4 million customers of the receiving utilities.

In response to the federal direction that states consider in advancing smart grid technologies, particularly those technologies that could advance energy efficiency, demand response, renewable energy, and grid reliability and security, in 2009 California enacted Senate Bill 17 into the Public Utilities Code. The bill establishes as state policy the modernization of the state's electrical grid to maintain reliable and secure electrical service with infrastructure that can meet future growth in demand while achieving several other objectives such as integration of distributed generation resources, demand-side resources and "smart" technologies. The bill further required California's investor-owned and large publicly owned utilities to develop plans that consider the deployment of smart grid technologies.

Several California POUs submitted plans in response to the requirements of SB 17, describing how POUs will deploy smart grid technologies to:

- Empower customers to use less energy through enhanced awareness of energy use and price-driven and automatic demand response.

- Integrate significant amounts of distributed renewable energy resources into utility transmission and distribution systems.
- Enhance the efficiency, security, reliability, and resiliency of transmission and distribution systems through advanced distribution automation systems.

While some of California's POUs are deploying smart grid technologies, others are not. Many POUs are waiting to better understand the potential impacts and benefits of smart grid technologies before making a significant investment in deployment. Lack of customer interest, high implementation cost, and uncertainty of benefits rank among the top reasons why some utilities choose to wait to make significant investment in smart grid technologies.

Research Participants

SAIC conducted extensive outreach to engage California's consumer-owned utility sector in this research. Of the 41 entities contacted, 16 agreed to participate including Northern California Power Agency (NCPA), California Municipal Utilities Association (CMUA), and the Southern California Public Power Authority (SCPPA); Alameda Municipal Power, Anaheim Public Utilities, Azusa Light Water, Burbank Water Power, Glendale Water Power, Imperial Irrigation District (IID), Los Angeles Department of Water and Power, City of Palo Alto Utilities, Pasadena Water and Power, Redding Electric Utility, Riverside Public Utilities, Sacramento Municipal Utility District (SMUD), and Silicon Valley Power. Participants provided input on the research method, provided valuable research data, and reviewed and commented on the research conclusions.

Current State of Smart Grid Deployment by Publicly Owned Utilities

This research focuses on the current and future states of smart grid technology deployment by publicly owned utilities. Current and future states are defined through a combination of surveys, interviews, and review of publicly available information regarding utilities' smart grid technology deployment.

The Carnegie Mellon Software Engineering Institute's Smart Grid Maturity Model (SGMM) provides the framework for capturing the current state and year 2020 vision of smart grid technology deployment. The SGMM identifies six maturity levels in eight domains of smart grid including:

Domains

- Strategy Management and Regulatory
- Organization and Structure
- Grid Operations
- Technology
- Work and Asset Management
- Value Chain Integration
- Customer

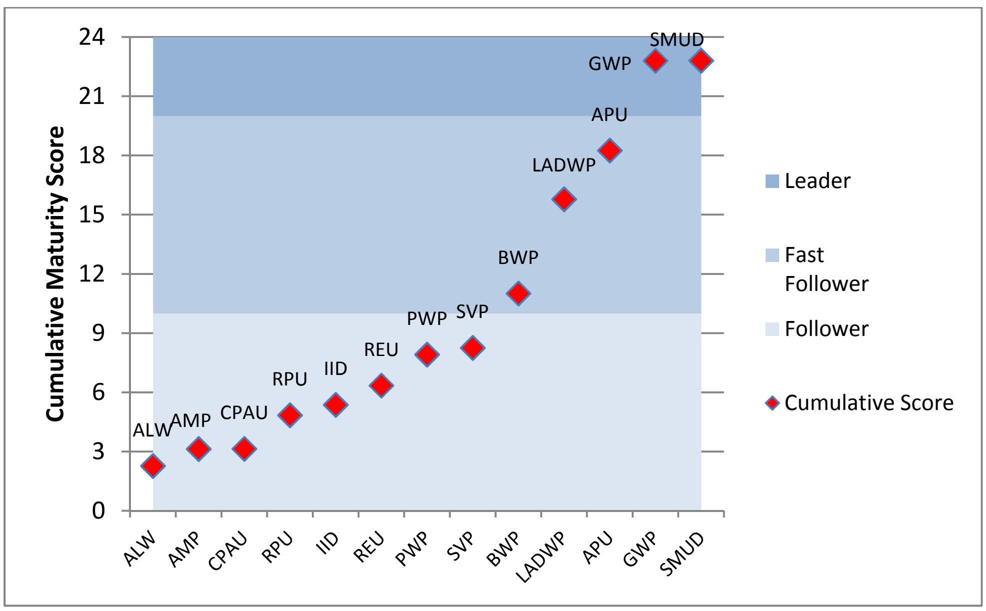
Maturity Levels

- Pioneering
- Optimizing
- Integrating
- Initiating
- Enabling
- Status Quo

- Societal and Environmental

The maturity of smart grid programs is determined by 175 expected characteristics defined in the SGMM. A survey determines which of these characteristics utilities exhibit in the current state. The survey results demonstrated that some of the State's POUs have very high maturity programs and that most of the participating utilities have low maturity programs. Analysis of the data indicated that utilities could be classified into three groups based on the maturity of the smart grid programs – leaders, fast followers, and followers. Leaders are the utilities with the most advanced level of smart grid plans and deployments. Fast followers were clearly planning and deploying smart grid technologies but at a slower pace and more limited scale than the leaders. Followers are utilities that are in the early stages of planning for smart grid technology deployment with no or very limited deployment. All of the participating utilities had some level of smart grid planning or deployment of technology.

Figure 1: Overall SGMM Results for Participating Utilities



ALW:	Azusa Light & Water	LADWP:	Los Angeles Water and Power
AMP:	Alameda Municipal Utility Power	PWP:	Pasadena Water and Power
APU:	Anaheim Public Utility	REU:	Redding Electric Utility
BWP:	Burbank Water and Power	RPU:	Riverside Public Utilities
CPAU:	City of Palo Alto Utilities	SMUD:	Sacramento Municipal Utility District
GWP:	Glendale Water and Power	SVP:	Silicon Valley Power
IID:	Imperial Irrigation District		

Leaders, SMUD and Glendale, generally exhibit a very mature and well-thought-out strategy based on their analyses that indicate the potential for customer benefits of a level sufficient to warrant significant investment in smart grid technologies. Both utilities believe that to sustain an excellent relationship with their customers and to meet their environmental and social objectives, their best solution is to invest in technologies that provide timely and detailed information to their customers about the costs and sources of energy that customers consume.

Fast followers like Anaheim, Burbank[1] and LADWP are investing significantly in smart grid technologies but generally at a slower pace than the leaders. LADWP is investing more than $50 million dollars into demonstrating smart grid technologies across all of the studied use cases. LADWP believes that investments in smart grid could total nearly a billion dollars. Its prediction is that smart technology costs will decline in the future and the benefits of investing in the technologies will become clearer. Accordingly, it is investing in those technologies, like substation automation, that have high levels of cost certainty and low levels of performance risk. The smart grid programs of both the leaders and fast followers have been accelerated and expanded as a result of federal stimulus funds that each received, primarily as a result of the effect that these funds have on reducing implementation costs.

Followers are generally at the "status quo" maturity level. Each of these utilities has demonstrated that the strategy that best meets the interests of its customers is to invest slowly in new technologies. Followers will closely watch and learn from the fast followers and leaders who are deploying technology more rapidly. The research demonstrates that this is a purposeful strategy and not the result a lack of planning. The City of Palo Alto, for example, completed a comprehensive strategic smart grid plan, concluding that its best strategy is to wait for the cost of smart grid technologies to decline, allow standards to mature and stabilize and follow closely the lessons learned from early adopters before making significant investments. These utilities generally believe that there is too much risk and uncertainty around the potential customer benefits to warrant spending capital that could provide more impact if invested in other activities such as operations and maintenance and infrastructure replacement. Most of California's public utilities and most utilities across the country fall into the follower category.

This research investigates the state of deployment of seven key applications of smart grid technologies. This report refers to these technology applications as "use cases," including:

1. **Substation Automation –** Substation automation can help utilities meet energy policy objectives by allowing bidirectional flow of power through protection and control devices designed for power flowing only to the customer; by providing a communications interface for advanced metering and distribution area networks; and by providing enhanced security and asset management.
2. **Advanced Metering –** Advanced metering infrastructure networks provide the platform for enhanced customer service options such as near-real-time energy cost and consumption information; remote service switching; prepay service; and, real-time outage notification data.
3. **Distributed Energy Resources (DER) –** Diverse energy sources located throughout the distribution system including wind and solar systems, energy storage, fuel cell and combined heat and power systems can enhance system reliability, improve system efficiency, and reduce the reliance on fossil-fueled energy sources.

[1] SAIC believes that because Burbank's smart grid program has advanced substantially since it conducted it Smart Grid Maturity Model assessment, the results of which are used herein, it would likely rank as a Leader in the context of this analysis if it were to make the assessment today.

4. **Demand Response –** Customers actively manage their energy consumption in response to information about their energy usage, rate, and market (events) information. Customer devices can either autonomously respond to rate/event information initiated by the utility or can be directly controlled by the utility. Advanced energy and demand management systems can optimize the dispatch of supply, demand, storage, and demand response to reduce costs and improve efficiency and reliability.
5. **Distribution Automation –** Widespread measurement, monitoring, control, and communications technologies are applied to the distribution system to reduce the extent and duration of outages, minimize electrical losses, maximize system efficiency, improve quality of service, and maximize the capacity of distribution system infrastructure.
6. **Electric Vehicle Charging –** Advanced charging systems allow widespread adoption of electric vehicle charging by controlling the time of day and rate at which electric vehicles charge to minimize the cost of charging, minimize the loading on the distribution system, and, in some cases, deliver energy back to the distribution system if needed for grid reliability and security.
7. **Asset Management –** Near-real-time monitoring of electric system equipment on a wide-scale basis, including transformers, conductors, and protective devices can be used to improve the maintenance and replacement of equipment, thereby minimizing operating and maintenance costs while maximizing system reliability.

Table 1: Smart Grid Use Case Applications by California POUs

Use Case	ALW	AMP	APU	BWP	CPAU	GWP	IID	LADWP	PWP	REU	RPU	SMUD	SVP
Substation Automation	◒	○	◒	◒	○	◒	◒	◒	○	●	◒	◒	◒
Advanced Metering	○	○	◒	●	○	●	⊙	◒	○		○	◒	⊙
Distributed Energy Resources	◒	◒	◒	◒	◒	◒	◒	◒	◒	◒	◒	◒	◒
Demand Response			○	○	⊙	⊙	⊙	⊙				●	
Distribution Automation	○	○	⊙	○	○	⊙	○	⊙	⊙	⊙	○	◒	⊙
Electric Vehicle Charging	○	○	⊙	⊙	⊙	⊙	⊙	◒	○	○	○	◒	⊙
Asset Management			◒	○		○	○	○	○		○	◒	
○Planning ⊙Piloting ◒Deploying ●Deployed													

California POUs are implementing the seven key smart grid technologies at varying paces and scales of deployment. All are currently deploying or enabling deployment and integration of distributed energy resources, primarily customer-owned rooftop solar, and most are also deploying or expanding the deployment of substation automation. The deployment of advanced metering infrastructure varies -- while half of the participating utilities are already deploying, the other half are mostly planning to deploy or piloting such technology. Distribution automation and electric vehicle charging applications are the other two areas where most participating utilities either have plans to deploy or are exploring their options through pilot projects. Demand response has been addressed by most utilities through time-of-use rates, although only a few large customers actually participate in time-based pricing programs. Demand response through direct load control has been deployed for some time by at least one utility but is seldom used, is considered ineffective in its current state, and is being replaced by a combination of direct load control and programmable controllable thermostats. Comprehensive, technology-driven asset management is the least adopted application by all participating utilities. Table 1 provides an overview of the current state of deployment by participating utilities.

2020 Vision of Smart Grid Deployment by Publicly Owned Utilities

After determining the current maturity levels, participating utilities used the Smart Grid Maturity Model to establish their expected year 2020 smart grid maturity levels. Through the aspirations-setting process of the model, participants identified their motivations for achieving their future visions and identified the actions to be taken and challenges that they may face along the way. Motivations are indicators as to why utilities intend to advance their smart grid maturity; actions represent the steps they will take to achieve their future aspirations, and challenges reflect the obstacles that they expect to face along the way. The results of this goal-setting exercise – the summary of motivations, actions, and obstacles – are identified as follows.

The most common motivations among the participants include:

- Meeting customer expectations and fulfilling social responsibility by adhering to regulatory requirements and increasing participation in green initiatives for reducing environmental impact (such as reducing greenhouse gas emissions, increasing demand response and peak-shaving capabilities, and increasing integration of renewable distributed energy resources and generation).
- Empowering customers to change their energy consumption by providing them with information about their energy use.
- Improving customer and employee safety, reliability of service, power quality, and system efficiency, and reducing operations and maintenance costs.
- Contributing to local economic development and communities through job creation
- Protecting customer privacy and maintaining a high degree of cyber security.

The most common actions that participants identified as being required to achieve their 2020 vision include:

- Educating internal and external stakeholders to create a common understanding of what smart grid is and what its benefits are to obtain buy-in for pursuing smart grid-related initiatives

- Developing, communicating, and adopting a utilitywide vision, goals, and strategy for smart grid.
- Acquiring necessary resources to identify, implement, and maintain smart grid and related initiatives
- Conducting pilot and proof-of-concept projects to identify what smart grid technologies and standards to implement.
- Creating a comprehensive information technology (IT) and communications vision and strategy plan that supports anticipated smart grid applications.
- Automating work order management, workforce management, and asset management processes.
- Implementing remote asset monitoring and sensing technologies to enhance pre-event awareness, asset condition and status monitoring, asset maintenance, and life-cycle management processes and costs
- Deploying advanced metering infrastructures to improve customer experience by proactive outage detection and notification, and providing on-demand usage data.
- Deploying customer premise solutions to enable visibility and control of customer premise devices and resources in response to demand response, load control, and system reliability events.

The most common challenges faced by participants in successfully meeting their 2020 aspirations include:

- Lack of customer interest, engagement, and willingness to participate in smart grid technologies.
- Finding sufficient capital resources to invest in technologies with uncertain benefits.
- Obtaining resources to successfully implement and maintain technologies.
- Uncertainty of potential smart grid benefits.
- Technology obsolescence and lifespan.
- Cultural inertia and resistance to change.
- Lack of information technology vision and planning and lack of understanding of the role of IT in smart grid.
- Regulatory uncertainty.
- Keeping up with evolving technologies and standards.
- Managing conflicting goals and priorities among internal and external stakeholders.

Through the aspirations-setting process of the Smart Grid Maturity Model, elements of a consistent vision of the future smart grid are identified. Some common expectations include the following:

- Low cost of service, high customer service, good reliability, and effective environmental responsibility are consistent vision elements.
- Education, training, and job creation are important drivers for POUs.

- Smart grid is not in and of itself a strategic objective; rather it is one of a number of potential solutions for meeting strategic objectives.
- The uncertainty of economic benefit from the deployment of smart grid technologies will slow the pace of deployment.
- By 2020, POUs will be at varying stages of maturity – some will be optimizing the application of smart grid technologies to achieve their service goals while many others will be in earlier stages of integration.
- Most POUs will not be pioneers of technology due to their higher level priority of providing low-cost service. POUs strive to achieve high customer service and good reliability not with leading edge technologies, which often cost more to implement and are hard to justify at the beginning, but with field-proven and tested technologies that have justifiable value proposition first and foremost to the utility customer.
- Regulatory and legislative pressures could cause adverse electric rate effects if utilities are mandated to deploy technologies faster than they are prepared for.

Developing a vision of the 2020 Smart Grid from the POU perspective is very difficult. The participating utilities are similar in that they are locally governed, customer-owned utilities that operate to provide safe and reliable services, provide good customer service, and provide low-cost electricity, water, and, in some instances, natural gas services to their customers. Beyond these similarities are a vast array of differences.

Based on the results of this research, and after review by the participating POUs, the expected 2020 vision for California's POUs was resolved to:

> A successful Smart Grid will enhance the electric, water, and natural gas service offerings POUs provide to their local communities, and improve the efficiency and reliability of the delivery system; lower overall system cost; support clean energy job creation and will be accomplished in a financially responsible manner at a pace and scope of deployment that reflects the financial, environmental and social priorities of the communities that govern and are served by local POUs.

Roadmap to California's 2020 Smart Grid for Publicly Owned Utilities

Participants used the Smart Grid Maturity Model to describe the current state of smart grid deployment, establish future deployment aspirations, and identify the actions they must take and challenges they must overcome to achieve their objectives. Based on a gap analysis between the current and future states of smart grid deployment as envisioned by the participating utilities, SAIC developed a set of technology roadmaps for each of the seven use cases and one roadmap emphasizing the evolution of business activities. The technology roadmaps are further defined to address the specific deployment pace of two classes of utilities – leaders and followers.

Each technology roadmap shows the evolution of each of the use cases across the five two-year time intervals from now to 2020. These use cases embody most of the smart grid functions and elements that POUs will address. In each two-year period for a specific use case, activities are identified that POUs will accomplish in fulfilling the role of leader or follower in smart grid deployment. The technology roadmaps focus on the hard technology for automating delivery of electric energy, and on the IT for managing that delivery. Many other supporting steps are essential to enable technology success. These steps occur in areas that enable and support the principal smart grid technologies named in the technology roadmaps and are defined in the following strategic focus areas:

- Planning
- Communications Infrastructure
- Instrumentation, Control, and Automation
- Information Technology
- Standards
- Training

The implementation roadmaps provide detailed instructions in these six focus areas, leading step-by-step to establish essential planning, supporting infrastructure and IT, and finally the smart grid content for each of the use cases. Utilities can use the technology and implementation roadmap templates resulting from this research to develop and refine their smart grid strategies.

Conclusions

Smart Grid Deployment Is Being Advanced by American Recovery and Reinvestment Act Funding

SGMM analysis found that the POUs that received stimulus grants are making substantive progress toward deployment of the smart grid. As a result of the ARRA-funded programs, these utilities accelerated and expanded the scope of their smart grid strategies while reducing the cost of deployment. As these programs mature, value information will be developed as to benefits that smart grid technologies can provide to consumers.

The High Cost and Uncertainty of Benefits Is a Barrier to the Deployment of Smart Grid Technologies.

The legacy of the electric utility industry is founded on the *certainty* of providing safe, reliable, and economical electricity. That passion for certainty pervades utility decision making and frequently manifests itself in pursuing business decisions and technologies that are risk adverse. In contrast, many smart grid applications are still relatively immature and lack a track record of proven field applications. Scarcity of historical data results in important uncertainties that subsequently affect POUs' ability to accurately estimate future costs and benefits of various smart grid options. Since cost/benefit analysis is fundamental to a POU's approach to economically justifying smart grid, some POUs may elect to take a "wait and see" approach. This observation is supported by noting that 8 out of the 13 surveyed POUs are classified as being followers and only two are considered to be leaders. Reducing the uncertainty in estimating smart grid costs and benefits will promote the implementation of smart grid in the POU space.

Regulatory Uncertainty Is a Barrier to the Deployment of Smart Grid Technologies

The roles and policies of regulatory agencies regarding smart grid continue to evolve. POUs are concerned about how future policies might "second guess" the choices that POUs are making today.

While some of California's POUs are deploying smart grid technologies, others are not. The cost of technology obsolescence and interoperability are two other key areas of concern that underlie many utilities' reluctance to deploy smart grid technologies right away. Utilities fear technology selections and deployments may become obsolete as further mandates and policies are put into place and technologies continue to change without set standards. Thus, many POUs are waiting to better understand the potential effects and benefits of smart grid technologies and evolution of standards before making a significant investment in deployment.

Smart Grid Deployment at POUs and IOUs Will Be Different

A number of differences exist between POUs and investor-owned utilities (IOUs) that will influence the deployment of smart grid, including:

- **Governance:** POUs are governed by boards that are composed of their consumers. POU boards are typically highly responsive to the consumers' needs and may be less educated about the technologies, services, benefits, or costs that are attributed to smart grid.
- **Capital Resources:** POUs' access to financial resources is limited and their capital budgets are subject to ratepayer scrutiny. POUs generally do not maintain sufficient retained earnings to fund an extensive smart grid deployment.
- **Human Resources:** POU staff is generally much smaller than IOU staff. Smart grid requires sufficient support for deployment, cyber security, and back office systems. Existing POU staff is often not adequately trained in smart grid.
- **Financial Incentives:** Financial incentives, like ARRA grants, are temporary solutions that do not provide a long-term solution to the financial challenges that many POUs face. POUs are not incentivized to maximize profits and financial benefits are returned to consumers.
- **Economies of Scale:** POUs generally have fewer customers to bear smart grid fixed costs, thereby impeding achievement of economies of scale. Many POUs cannot develop a positive business case for smart grid technology and are unwilling to require customers to pay higher rates for the sake of technology.

Recommendations

Additional Research Is Needed to Reduce the Cost of Smart Grid Deployment

POUs commonly justify smart grid deployment on the basis of forecasted costs and benefits. To date, some POUs have estimated costs to be in excess of benefits and have consequently elected for costs to decline. Reductions in smart grid costs will increase deployment, especially at smaller utilities, but it is not clear how much the costs have to decline to have a significant effect on the rate of deployment. Since the Energy Commission already invests in research to reduce the costs of technologies such as renewable energy and energy efficiency, it should consider researching how reducing the costs of advanced metering, distribution automation, energy storage, and demand response may advance the effect of smart grid technologies on achieving energy policy objectives.

Additional Research Is Needed to Identify the Smart Grid Effects on Energy Policy

This report identifies specific ways that smart grid could positively affect California's energy policy. However, progress in such accomplishments is currently unproven, and there are no data to quantitatively measure progress. Over the next few years, the Energy Commission should track and measure how Smart Grid is influencing key outcomes among POUs, such as:

- Reduce greenhouse gasses (GHG).
- Integrate rooftop solar panels.
- Adhere to renewable portfolio standards.
- Modify resource plans to first use energy efficiency, conservation, and distributed resources.

Extend Outreach for Smart Grid Education

Interviews with POUs identified smart grid education for boards, staff, and consumers as a significant obstacle. POUs regularly survey their customers' interest in technologies for reducing energy consumption and reducing the environmental impact of electricity consumption, including perceptions of the potential costs and benefits of smart grid. POU customers are generally willing to accept that using smart grid technologies to accomplish "good" things is something they would support, but they are usually not interested in paying anything additional and are suspect as to the potential benefits. Whereas the Energy Commission has been involved in outreach to California's energy consumers about the positive effects of energy efficiency and renewable energy, similar efforts could be applied to helping consumers understand the potential positive impacts that smart grid technologies may have toward meeting energy policy objectives. Particularly important areas for education could include privacy and security, health effects, reliability, and the tangible financial benefits associated with smart grid technologies.

Encourage Customer Participation

One issue that confronts a successful smart grid launch is the role of customers. Many of the financial benefits that smart grid offers may not be fully realized if customers are not adequately engaged and participating on an ongoing basis. Once the newness of the offering (such as home area networks) has faded, customers might lose interest and revert to traditional behaviors.

Develop a Standardized Framework to Help POUs Quantify the Benefits and Costs Associated With Smart Grid

> This will require a complex modeling approach and should include technology and customer programs such as DR modeled over a 15-year time frame, at a minimum. It should be capable of modeling multiple smart grid applications simultaneously to understand a utility's entire smart grid return on investment and cash flow for budgeting, to have the capability to quantify the financial implications of alternative strategies, and to provide insights on the timing and integration of smart grid initiatives across the enterprises.

Continue to Track and Monitor POU Smart Grid Progress

Implementing the SGMM framework provided insight into the status of smart grid development at POUs. Since it is a measurement at a point in time, tracking the POUs' progress over time and timely success in achieving future aspirations, it is recommended that the Energy Commission support the application of SGMM at two-year intervals through 2020.

The SGMM is a powerful tool yet has certain areas where refinement is recommended to track the unique needs and circumstances of POUs. Specific examples include survey question modifications to reflect POU governance (POUs are not regulated in the same manner as IOUs), concept of the utility's grid (the POU's grid is predominantly a distribution system, yet some SGMM questions pertain to the transmission or generation systems), and services (many POUs offer water and natural gas in addition to electricity – SGMM questions do not account for economies of scope that may be available by addressing multiple services).

Address Unique POU Challenges in Smart Grid Development

POUs face certain challenges that are significantly different from IOUs. Consequently, it is not surprising to find that the Energy Commission's role in promoting smart grid in the POU space needs to take into account a different set of challenges. Specific examples include size (POUs are commonly smaller than IOUs and, therefore, have fewer human resources to draw upon in implementing a smart grid program), financing (POUs' access to capital is significantly different from IOUs) and governance (POUs need to be responsive to an elected board, which reflects the interests of its ratepayers).

Another challenge is that costs associated with many, necessary smart grid functions are not well scalable. Regardless of size, utilities are expected to require specialized expertise in cyber security, back-office support and software, communications, and management. To a large extent, these features disadvantage smaller utilities (most notably POUs) and adversely affect the economic justification of smart grid. It is recommended that the Energy Commission support research into scaling smart grid systems to better fit smaller utilities.

Few POUs in California own and operate transmission systems (such as, IID, LADWP, and SMUD), and the others rely on third parties (such as, joint agencies such as the Southern California Public Power Authority). One smart grid application that has received comparatively less attention in this research is transmission systems and synchrophasors. The role that nontransmission owners play in such areas is limited and should be explored more.

Engage California POUs in Smart Grid Evolution and Standards Development Processes

POUs should engage more with energy operators, technology providers, and regulators to understand what standards are in place, and what the consequences of failing to meet those standards are. What new developments are on the horizon? How risk management and controls related to adoption of standards should be integrated into the entire smart grid project lifecycle? How they should apply technical, operational, and management controls according to best practices?

The Energy Commission should develop an ongoing discussion and interaction with California POUs to engage them more in developing standards by working with manufacturers and the Energy Commission to provide data and pilot demonstrations. The Commission should create a platform for information sharing and continued discussion between the POUs and the Energy Commission around enabling smart grid technologies and standards, the state of implementation of technologies, standards and pilot demonstrations, lessons learned, the evolving risks, impacts, and possibilities.

Continue Participating in Cyber Security and Data Privacy Issues

Smart grid implementation in some California communities has raised questions about the security of utility networks and the privacy of customer data. Cyber security is a process and not an endpoint. Therefore, POUs will need to make an ongoing investment in their IT processes and staff to ensure that adequate safeguards are in place and updated.

CHAPTER 1: Introduction

This research report provides insight into the unique perspective shared among California's customer-owned public utilities (the POUs) of the issue of whether and how the deployment of Smart Grid technologies can help meet state energy policy objectives. To investigate this issue several key questions are examined:

1) How does the deployment of Smart Grid technology help a POU achieve state energy policy objectives?
2) How are POUs deploying Smart Grid technologies today?
3) What is the vision of the 2020 Smart Grid from the perspective of POUs?
4) What are the challenges that POU's face in implementing Smart Grid technologies?
5) How can the Energy Commission apply its research efforts to help POU's address these challenges?

In this first chapter of the report, the basis for the investigation is set by:

- Establishing the connection between Smart Grid technologies and the impact on state energy policy objectives
- Defining the nature of POUs as providers of energy and other essential services to consumers, and
- Presenting the unique POU perspective of the 2020 smart grid

Chapter 2 of the report presents the POU vision for the 2020 Smart Grid.

Chapter 3 of the report presents the current state of Smart Grid deployments, describes the plans for future deployments and identifies gaps and challenges the POU's must overcome in Smart Grid deployments.

Chapter 4 provides an assessment of Smart Grid technologies being used by POUs.

Chapter 5 provides a framework for and discusses the challenges POUs face in building a positive Smart Grid business case.

Chapter 6 presents a broad technology roadmap for POU deployment of Smart Grid technologies and provides detailed Smart Grid implementation roadmaps.

Chapter 7 presents the concluding comments of SAIC for California POUs and the Energy Commission to achieve the 2020 Smart Grid vision.

Chapter 8 provides the list of acronyms.

Appendix A supplements Chapter 3 (California Smart Grid Initiatives Assessment Framework) with additional information on the Smart Grid Maturity Model (SGMM) framework describing its benefits, domains and underlying assumptions. This appendix also provides in-depth data and analysis of the California POUs' SGMM results.

Appendix B also supplements Chapter 3 (California Smart Grid Initiatives Assessment Framework) with detailed information on the Smart Grid initiatives of the California POUs that have received American Recovery and Reinvestment Act (ARRA) grants.

Appendix C supplements Chapter 4 (Smart Grid Technology Assessment) with detailed information on the Smart Grid technologies. This appendix is structured in a tutorial nature. It discusses Smart Grid technologies that are emerging and in-service, some at California POUs.

Appendix D also supplements Chapter 4 (Smart Grid Technology Assessment)and provides detailed information on each Use Case. The Use Cases are structured in a flyer format. Each Use Case presents; a brief description of the Use Case application; primary business and operational needs addressed and impacted by the implementation of the Use Case; a high level hardware, software, communications, interface and training requirements to enable the suggested Use Case; technology and business challenges that a utility may face while implementing the Use Case; and, a brief summary of its benefits and potential.

Appendix E supplements Chapter 5 (Smart Grid Business Case Framework) with a discussion on the employment and job creation related aspects of Smart Grid.

Energy Policy Objectives and Legislation

California has a broad range of energy policy objectives that impact the customer-owners of POU's. The overarching objective of California's energy policy is to reduce the use of fossil-based fuels that when consumed in producing electricity generates greenhouse gasses (GHG) that are emitted to the atmosphere. These policies and related regulations and legislation direct utilities to:

- Reduce energy use by increasing energy efficiency in customer premises and in the grid;
- Reduce the use of fossil-fueled energy sources by increasing the use of clean renewable energy resources including utility scale installations and widespread distributed scale;
- Motivate, and in some instances require, consumers to reduce energy use during peak consumption periods when energy is most scarce, is most expensive to produce and deliver and is generated by the least efficient, highest-GHG emitting sources; and,
- Provide efficient, reliable, secure and resilient transmission and distribution grids.

In 2007, the Federal Government enacted the Energy Independence and Security Act of 2007, Title XIII of which lays the foundation for current interpretations of Smart Grid terminology. In Title XIII, a national Smart Grid policy is enacted to support the modernization of the Nation's electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet future demand growth and to achieve each of the following, which together characterize a Smart Grid:

(1) Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid.

(2) Dynamic optimization of grid operations and resources, with full cyber security.

(3) Deployment and integration of distributed resources and generation, including renewable resources.

(4) Development and incorporation of demand response, demand-side resources, and energy-efficiency resources.

(5) Deployment of ''smart'' technologies (real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering, communications concerning grid operations and status, and distribution automation.

(6) Integration of ''smart'' appliances and consumer devices.

(7) Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air conditioning.

(8) Provision to consumers of timely information and control options.

(9) Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid.

(10) Identification and lowering of unreasonable or unnecessary barriers to adoption of Smart Grid technologies, practices, and services.

The American Recovery and Reinvestment Act of 2009 (Recovery Act or ARRA) provides the U.S. Department of Energy (DOE) with about $4.5 billion to modernize the electric power grid and to implement Title XIII of the Energy Independence and Security Act of 2007 (EISA), which focused on the Smart Grid. The two largest initiatives are the Smart Grid Investment Grant (SGIG) program and the Smart Grid Demonstration Program (SGDP.) SGIG focuses on deploying existing Smart Grid technologies, tools, and techniques to improve grid performance today. SGDP explores advanced Smart Grid and energy storage systems and evaluates performance for future applications. California's POUs received federal stimulus grant of $321 million towards total program costs of $558 million. These Smart Grid investments equate to approximately $240 per each of the 2.4 million customers of the receiving utilities.

In response to the federal direction that states consider advancing Smart Grid technologies, particularly those technologies that could advance energy efficiency, demand response, renewable energy and grid reliability and security, in 2009 California enacted Senate Bill 17 into the Public Utilities Code. The bill establishes as state policy the modernization of the state's electrical grid to maintain reliable and secure electrical service with infrastructure that can meet future growth in demand while achieving several other objectives such as integration of distributed generation resources, demand-side resources and 'smart' technologies. The Bill further required California's investor owned and large publicly-owned utilities to develop plans that consider the deployment of Smart Grid technologies.

Several of California's POU's submitted plans in response to the requirements of SB-17 describing how POU's will deploy Smart Grid technologies to:

- Empower customers to use less energy through enhanced awareness of energy use and price-driven and automatic demand response;
- Integrate significant amounts of distributed renewable energy resources into utility transmission and distribution systems
- Enhance the efficiency, security, reliability and resiliency of transmission and distribution systems through advanced distribution automation systems

Research Participants

Science Applications International Corporation (SAIC) invited 38 municipal utilities, along with Northern California Power Agency (NCPA), California Municipal Utilities Association (CMUA), and the Southern California Public Power Authority (SCPPA) to participate in the project. The table below lists the 13 participating utilities.

Table 2: California Publicly Owned Utilities

Utility Information	# of Customers	MWh Sold (2009)	Services	Participant	ARRA Recipient
Alameda Municipal Power	34,399	383,100	E,B	Y	N
Anaheim Public Utilities	112,548	3,208,123	E,W,B	Y	Y
Azusa Light Water	15,403	679,596	E,W	Y	N
Banning Public Utilities	11,800	150,287	E	N	N
Burbank Water Power	51,619	1,183,987	E, W,WW,B	Y	Y
City of Cerritos	305	60,000	E	N	N
Colton Public Works and Utility Services	18,694		E,W	N	N
Corona Water Power	1,883		E,W	N	N
Glendale Water Power	84,800	1,287,976	E,W,WW,B	Y	Y
City of Gridley	2,886	32,875	E,W	N	N
City of Healdsburg	5,594		E,W	N	N
City of Hercules	750	13,269	E	N	N
Imperial Irrigation District	145,626	3,316,121	E,W,B	Y	N
Lassen Municipal Utility District	10,700	133,000	E	N	N
City of Lodi	25,500	434,270	E,W	N	N
City of Lompoc	15,282	134,000	E,W,WW	N	N
Los Angeles Department of Water Power	1,400,000	24,838,982	E,W,B	Y	Y
Merced Irrigation District	7,567	425,600	E,I	N	N
Modesto Irrigation District	107,141	2,786,159	E	N	Y
City of Moreno Valley	5,589	90,526	E	N	N

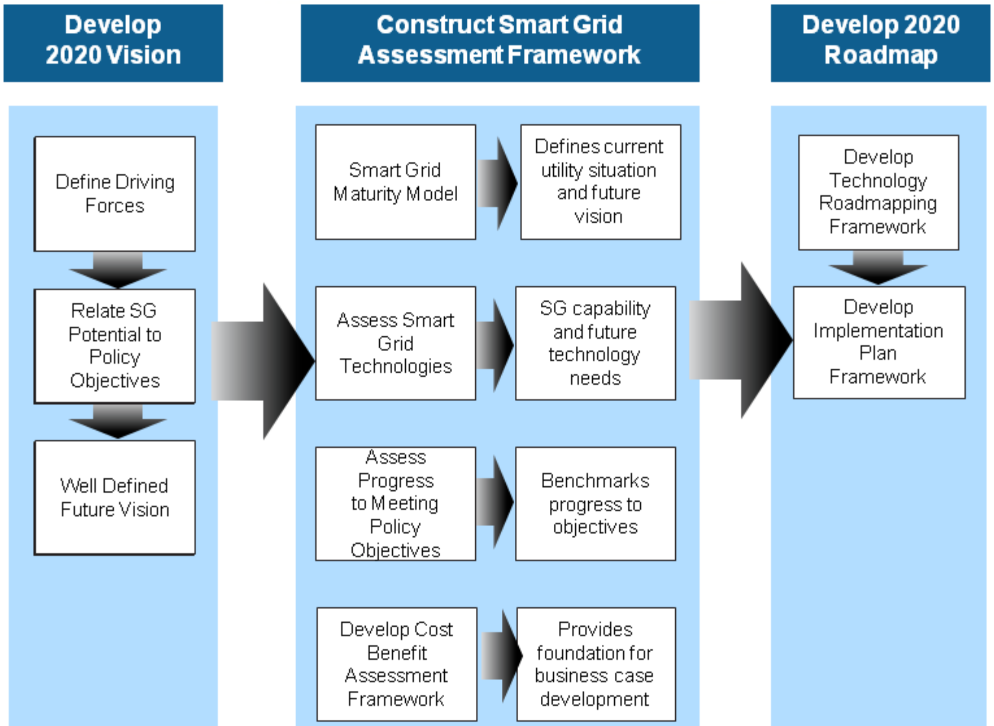
Utility Information	# of Customers	MWh Sold (2009)	Services	Participant	ARRA Recipient
Needles Public Utility Authority	3,113	57,756	E,W	N	N
City of Palo Alto Utilities	29,430	965,000	E,G,W,WW,B	Y	N
Pasadena Water and Power	63,838	1,184,344	E,W,B	Y	N
Pittsburg Power Company	449	17,479	E,G	N	N
City of Rancho Cucamonga	487	66,000	E	N	N
Redding Electric Utility	43,035	770,000	E,W	Y	N
Riverside Public Utilities	106,385	2,089	E,W,WW,B	N	N
Roseville Electric Utility			E,W	N	N
Sacramento Municipal Utility District	595,076	12,800,000	E	Y	Y
San Francisco Public Utilities Commission	2,206	R: 967,466 W: 283,026	E,W	N	N
Silicon Valley Power	51,854	2,800,004	E,W,WW,B	Y	N
City of Shasta Lake	4,441	189,944	E,W	N	N
South San Joaquin Irrigation District			E,W	N	N
Trinity Public Utilities District	7,119	89,000	E	N	N
Truckee Donner Public Utility District	13,154	146,875	E,W	N	N
Turlock Irrigation District	98,453	R: 1,988,956 W: 1,440,480	E,I	N	N
City of Ukiah	8,500	117,821	E,W	N	N
City of Vernon Light Power	1,908	1,208,000	E,W	N	N
Legend					
Participating Utilities are Shaded	ARRA – American Recovery and Reinvestment Act B – Broadband E – Electric G – Gas I – Irrigation MWH – Megawatt-hour W – Water WW – Waste water				

As presented in Table 2, five of the participating POUs received American Recovery and Reinvestment Act (ARRA) grants from the United States (U.S.) Department of Energy (DOE) in 2009 for their Smart Grid initiatives. The project value of the Smart Grid initiatives of these POUs totals to approximately $555 million, dollars of which $233.6 million dollars are funded by the DOE through the ARRA grant.

Approach and Methodology

SAIC employed a stakeholder driven approach to working with the State's POU's. Of the 13 participants, several utilities were asked to serve as ad-hoc steering committee members. Working with these steering committee members, the project team selected the Smart Grid Maturity Model (SGMM) as primary instrument for gathering and analyzing information about POU smart grid vision and implementation plans. The research approach adopted by the project team is presented in the figure below. The application of the SGMM framework and the resulting findings are further described in Chapter 3.

Figure 2: Research Approach



The SGMM is a management assessment tool that was initially developed by International Business Machines (IBM) and a group of Investor Owned Utilities (IOUs) and POUs. The model is currently under the stewardship of the Software Engineering Institute (SEI) at Carnegie Mellon University (CMU), which continues to solicit input from electric utilities to guide its on-going development. Gas and water utilities have not participated in the SGMM. The model provides a framework for understanding the current state of Smart Grid deployment and capability within an electric utility, regardless of its ownership structure, and provides a context for establishing future strategies and work plans as they pertain to Smart Grid implementations. The model is objective in nature, quantitative, and applies a highly structured approach to collecting data from electric utilities. These features facilitate meaningful cross-utility comparisons and aid an individual utility's understanding how they compare to other similarly sized entities.

The SGMM is composed of eight model domains that each contains six defined levels of maturity, ranging from Level 0 (lowest) to Level 5 (highest). Each domain is a logical grouping of specific Smart Grid capabilities and characteristics. An SGMM assessment provides an organization with a maturity rating for each of the eight domains. The six levels of maturity represent defined stages of an organization's incremental progress toward achieving an advanced state in terms of automation, efficiency, reliability, energy and cost savings, integration of alternative energy sources, improved customer interaction, and access to new business opportunities and markets.

Figure 3: Smart Grid Maturity Model Consists of Eight Smart Grid Domains

Source: Smart Grid Maturity Model, Model Definition, *A framework for Smart Grid transformation* September 2010, TECHNICAL REPORT, CMU/SEI-2010-TR-009, ESC-TR-2010-009

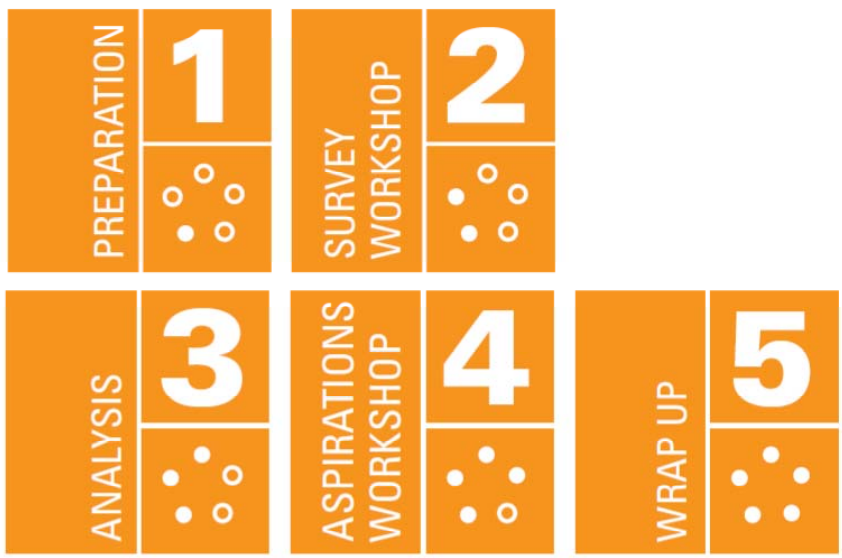
Figure 4: Six Maturity Levels of Smart Grid Maturity Model

Source: Smart Grid Maturity Model, Model Definition, *A framework for Smart Grid transformation* September 2010, TECHNICAL REPORT, CMU/SEI-2010-TR-009, ESC-TR-2010-009

Applying the model begins with an assessment using the SGMM Compass, a survey instrument containing questions corresponding to the characteristics in the SGMM model, as well as demographic and performance information. Completing the Compass survey and having it scored yields a maturity rating for each of the model's eight domains. The levels of maturity represent defined stages of an organization's progress toward achieving its Smart Grid vision in terms of automation, efficiency, reliability, energy and cost savings, integration of alternative energy sources, improved customer interaction, and access to new business opportunities and markets. By assessing its current maturity level in each domain and taking steps to increase its levels as appropriate, an organization will move closer to obtaining the desired benefits of implementing Smart Grid features. The flexibility of the model allows a utility to establish its own unique target maturity profile as a target for Smart Grid implementation.

In addition to the maturity ratings, each Compass scoring report also includes aggregate data from all of the utilities that have completed the survey. Using this data, a utility can compare its survey responses and maturity profile to the community of SGMM users. Many utilities have reported that this comparison yields additional insights about their Smart Grid progress and plans.

Figure 5: Smart Grid Maturity Model Assessment Process



Source: Smart Grid Maturity Model, Model Definition, *A framework for Smart Grid transformation* September 2010, TECHNICAL REPORT, CMU/SEI-2010-TR-009, ESC-TR-2010-009

Utilities electing to participate in the research considered three options for conducting an SGMM assessment and using the model.

SGMM Navigation – SAIC provides SGMM Navigators who are industry experts who have been trained and certified to guide utilities through the SGMM Navigation process. The Navigator works with the utility's Smart Grid team to complete the SGMM Compass on a consensus basis in a workshop setting—promoting valuable internal discussion of shared objectives.

Self-Assessment - Utilities may also complete the SGMM Compass independently. They receive a scoring report with a maturity level profile against the model, as well as aggregate data from the other utilities that have completed the survey for use in comparative analysis.

Utilities choosing the self-assessment option will have access to SAIC Navigators who provide individualized coaching to help interpret the results.

Group-Assessment - Utilities may also complete the SGMM Compass as a group in a workshop setting with facilitation by an SAIC Navigator. They receive individual scoring reports with a maturity level profile against the model, as well as aggregate data from the other utilities that have completed the survey for use in comparative analysis.

As shown in the table below, about half of the participating utilities elected to self-assess while the others elected to engage in the facilitated SGMM Navigation process.

Table 3: Survey Participants Assessment Elections

Self-Assessed	Navigated Assessment
Glendale Water and Power	Sacramento Municipal Utility District
Burbank Water and Power	Los Angeles Department of Water and Power
Anaheim Public Utilities	Imperial Irrigation District
City of Palo Alto Utilities	Riverside Public Utilities
Silicon Valley Power	Pasadena Water and Power
Alameda Municipal Power	Redding Electric Utility
Azusa Light and Water	

Seven Use Cases Define POU Application of Smart Grid Technologies

As a result of the SGMM process, SAIC identified seven use cases, summarized below and further described in Chapter 4, to illustrate ways in which Smart Grid is widely expected to benefit utilities and energy users in California and elsewhere in 2020. These use cases provide a detailed description of the function and application of smart grid technologies in categories that were originally established by the National Institute of Standards and Testing . Describing the application of smart grid technologies in the context of these use cases provides some consistency for the purposes of description and comparison. In the technology assessment discussion in Chapter 4, the use cases serve as a reference against which present and future technology capabilities are compared to define the gap between now and the possible capabilities of 2020.

Figure 6: Seven Use Cases Define POU Application of Smart Grid Technologies

Seven Use Cases Define Utility Application of Smart Grid Technologies	Key Energy Policy Objectives						
	Reduce GHG	Demand Response	Energy Efficiency	Renewable Energy	Grid Resiliency	Distributed Energy	Electric Vehicles
SUBSTATION AUTOMATION Integrated Protection and Control Improves Service Reliability				✓	✓	✓	
ADVANCED METERING Smart Meters Enhance Utility-Customer Interaction	✓	✓		✓			
DISTRIBUTED ENERGY RESOURCES Integrated Distributed Generation & Storage Provides Reliable Clean Renewable Energy	✓		✓		✓	✓	
DEMAND RESPONSE Active load management reduces peak demand	✓		✓		✓	✓	✓
DISTRIBUTION AUTOMATION Voltage Management Improves Power Quality, Delivery Efficiency, and Customer Service	✓		✓		✓		
ELECTRIC VEHICLE CHARGING Grid Monitoring and Control Enables Wide-scale Electric Vehicle Charging	✓						✓
ASSET MANAGEMENT Asset Monitoring Enables Proactive System Planning and Maintenance	✓		✓	✓	✓	✓	✓

1. **Substation Automation -** Substation automation can help utilities meet energy policy objectives by allowing bidirectional flow of power through protection and control devices design for power flowing only to the customer; by providing a communications interface for advanced metering and distribution area networks; and by providing enhanced security and asset management.
2. **Advanced Metering -** Advanced metering infrastructure (AMI) networks not only provide the platform for enhanced customer service options such as remote service switching and pre-pay service but also play a critical role in utility's outage management process by providing real-time outage notification data from the customer/metering locations. It can further enhance the utility's engineering, system operations, management and planning processes.
3. **Distributed Energy Resources (DER) -** Diverse energy sources are located throughout the distribution system, including small wind and rooftop solar systems, the energy output of which is highly variable. Energy storage devices connected throughout the distribution system include flywheels, batteries, and thermal devices. In addition, the utility may have a direct load control program controlling such customer loads as air conditioning, pool pumps, and water heaters.
4. **Demand Response -** Customers actively manage their energy consumption in response to information about their energy usage, rate and market (events) information. Customer devices can either autonomously respond to rate/event information initiated by the utility or can be directly controlled by the utility. More complex dynamic rate structures can be established requiring customer devices to be equipped with automated

systems that can autonomously react to utility price signals to fully capture the customer driven load response.

5. **Distribution Automation -** Near-real-time status and reading data are acquired via Supervisory Control and Data Acquisition (SCADA), AMI, or other remote sensors on the distribution network. Distribution automation applications such as Automated Feeder Management system dynamically collects this data from distribution feeders and, when a fault occurs, automatically isolates the fault and restores electric service by switching un-faulted line segments to adjacent feeders with free capacity. Volt-VAR Control (VVC) controls capacitor banks, load tap changers, and voltage regulators to regulate distribution voltage and minimize volt-ampere reactive (VAR) flows through distribution lines. Voltage control and VAR control can be operated independently, but optimal benefits are achieved when they are integrated. A state estimator and load flow analysis programs of a distribution management system (DMS) determine the voltage profile for each circuit, and switch capacitor banks and/or feeder sections to optimize the circuits. Once the voltage profile is optimized, substation regulators reduce the feeder voltage to near the practical minimum, reducing losses and saving energy.
6. **Electric Vehicle Charging -** A plug-in electric vehicle (PEV) connected for charging, links with the utility via the home area network (HAN), the meter, and the AMI network. The PEV displays and the in-home display (IHD) show the customer the battery status and energy cost information, and the customer chooses a charging schedule and fee that meet the customer's needs. If the customer chooses to participate in utility demand response and/or emergency load shed, the PEV may be restricted from charging until an emergency event concludes. The PEV may even discharge to give the grid power for a time. The PEV returns to the user prescribed charging scenario after a discharging event is complete or expired.
7. **Asset Management -** Smart Grid enables more complete data acquisition thus more accurate planning. Engineers can better predict load growth by applying data collected through distribution monitoring systems to a complete network model. System losses may be reduced by identifying load imbalances and redistributing load. Logged data identify feeders with excessive VAR flow as candidates for capacitor bank installations, reducing losses and extending equipment life. Correct operation of protective devices is verified by digital fault data acquired from microprocessor-based relays and recloser controls. Preventative maintenance may be driven by historical recloser and breaker operation trends, instead of by static timelines.

Technology and Implementation Roadmaps

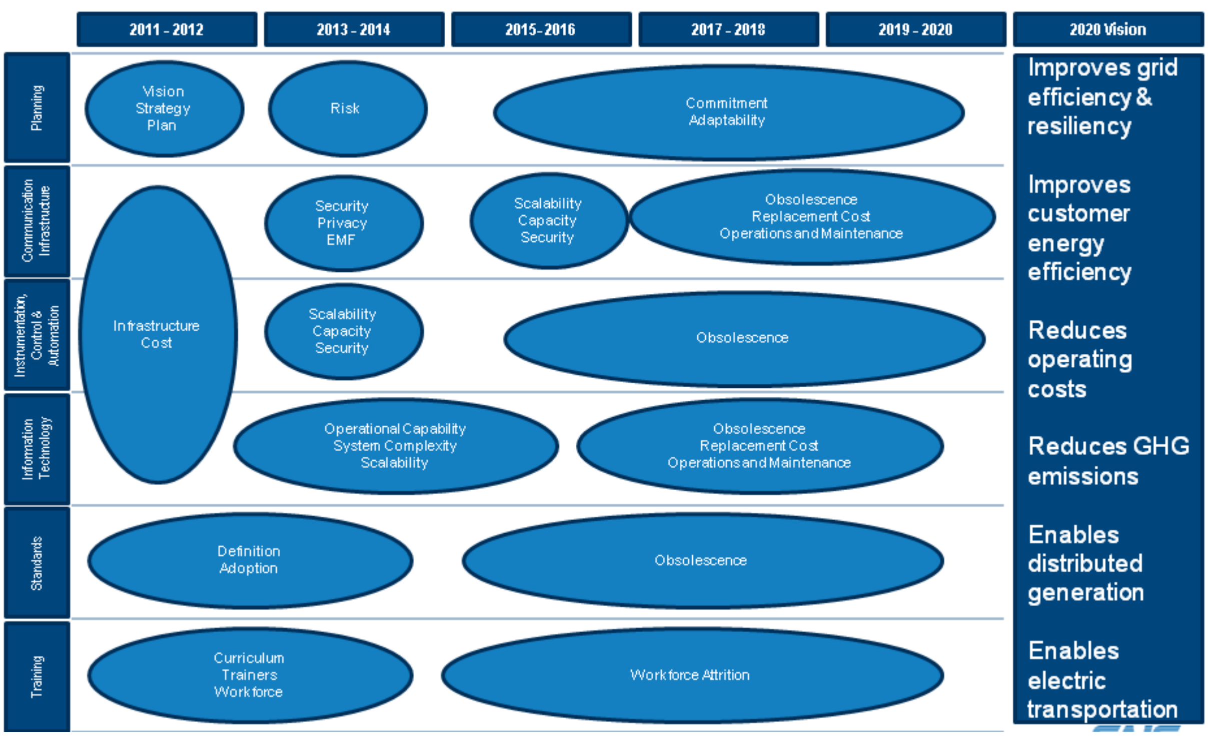
The SGMM framework comprehensively addresses organizational and business information technology (IT) matters. However, its insight is less detailed into the electrical and electronic technologies of utility automation, and the IT resources that support them. The Technology Roadmap approach utilized by SAIC, and further described in Chapter 6, for this project emphasizes these elements. POU planners will recognize the additional need for the SGMM business activities, and will use the SGMM roadmap as a complementary planning tool.

Each Technology Roadmap shows the evolution of each of the use cases across the five two-year time intervals from now to 2020. These use cases embody most of the Smart Grid functions and elements that POUs will address. In each two-year period for a specific use case, activities are identified that POUs will accomplish in fulfilling the role of Leader or Follower in Smart Grid deployment. The Technology Roadmaps focus on the hard technology for automating delivery of electric energy, and on the IT for managing that delivery. Many other supporting steps are essential to enable technology success. These steps occur in areas that enable and support the principal Smart Grid technologies named in the Technology Roadmaps, and are defined in the following strategic focus areas:

- Planning
- Communications Infrastructure
- Instrumentation, Control & Automation
- Information Technology
- Standards
- Training

The Implementation Roadmaps provide detailed instructions in these six focus areas, leading step-by-step to establish essential planning, supporting infrastructure and IT, and finally the Smart Grid content for each of the use cases.

Figure 7: Representative Technology Roadmap for Use Case



CHAPTER 2: California's Smart Grid Vision of 2020 for Publicly Owned Utilities

Developing a vision of the 2020 Smart Grid from the publicly-owned utility (POU) perspective is very difficult. The participating utilities are similar in that they are locally-governed, customer-owned utilities who operate to provide safe and reliable services, provide good customer service and provide low-cost electricity, water and in some instances natural gas services to their customers. Beyond these similarities are vast array of differences. Consider these observations:

Participants in the project range from the largest POUs in the nation to the smallest POUs in the nation. Los Angeles Department of Water and Power (LADWP) serves 1.4 million customers while City of Palo Alto Utilities (CPAU) serves less than 30,000 customers. LADWP, Sacramento Municipal Utility District (SMUD) and Imperial Irrigation District (IID) own and operate thousands of miles of transmission lines interconnecting California, Oregon, Nevada, Arizona, New Mexico and Mexico. Alameda Municipal Power and most other participants operate no transmission systems. Some utilities are governed by City Councils and others by Utility Boards. A staggering array of differences of size, services, governance, energy sales result in a wide range of priorities -- especially priorities regarding Smart Grid technologies.

Proposed Draft Publicly Owned Utility Vision

Through the aspirations setting process of the SGMM, elements of a consistent vision of the future Smart Grid are uindentified. Some common expectations include:

- Low cost of service, high customer service, good reliability and effective environmental responsibility are consistent vision elements;
- Education, training and job creation are important drivers for POUs;
- Smart Grid is not in and of itself a strategic objective, rather it is one of a number of potential solutions for meeting strategic objectives
- The uncertainty of economic benefit from the deployment of Smart Grid technologies will attenuate the pace of deployment;
- By 2020, POUs will be at varying stages of maturity – some will be optimizing the application of Smart Grid technologies to achieve their service goals while many others will be in earlier stages of integration;
- Most POUs will not be pioneers of technology due to their higher level priority of providing low cost service. POUs strive to achieve high customer service and good reliability not with leading edge technologies which often cost more to implement and are hard to justify at the beginning, but with field-proven and tested technologies that have justifiable value proposition first and foremost to the utility customer; and,
- Regulatory and legislative pressures could cause adverse electric rate impacts if utilities are mandated to deploy technologies faster than they are prepared for.

Based on the results of this research, and after review by the participating POU's, the expected 2020 vision for California's POU's was resolved to:

> A successful Smart Grid will enhance the electric, water, and natural gas service offerings POUs provide to their local communities, and improve the efficiency and reliability of the delivery system; lower overall system cost; support clean energy job creation and will be accomplished in a financially responsible manner at a pace and scope of deployment that reflects the financial, environmental and social priorities of the communities that govern and are served by local POUs.

CHAPTER 3: California Smart Grid Initiatives Assessment Framework

Smart Grid Maturity Model

Introduction to SGMM Framework

Fundamental objectives of this project include identifying the status of Smart Grid at California publicly-owned utilities (POUs), conducting comparisons between California's POUs and electric utilities at large and assessing POU's Smart Grid aspirations for the year 2020. This information provides the Energy Commission with guidance to promote Smart Grid adoption within the POU space to better accomplish California's energy policy objectives (such as, reduce greenhouse gasses to pre-1990 levels, accomplish solar rooftop objectives, increase renewable energy generation and achieve loading order objectives). The purpose of this section is to present an approach to Smart Grid assessment, apply it to quantitatively measure the status of Smart Grid at California's POUs and then make comparisons between the POUs. Lastly, aspirations of POUs are examined to establish an understanding of where their Smart Grid programs are forecasted to be in the year 2020.

SGMM Overview

Accomplishing these objectives is accomplished, in part, by applying Carnegie Mellon University's Software Engineering Institute (CMU) Smart Grid Maturity Model (SGMM). The SGMM is composed of eight model domains. Each domain contains six defined levels of maturity, which range from Level 0 (lowest) to Level 5 (highest). Domains are logical grouping of specific Smart Grid capabilities and characteristics. The outcome of the SGMM assessment is a maturity rating for each of the eight domains The SGMM follows an underlying philosophy that a utility should first understand its current status (or maturity) in each domain and then take steps to increase its maturity to obtain the full benefits of adopting and implementing Smart Grid. SGMM maturity levels organize the characteristics of the model's eight domains into hierarchical groupings. Each level builds upon the levels below it; an organization must achieve Level 1 in a particular domain prior to achieving Level 2 in that domain. Achieving a particular maturity level within a domain requires the utility to demonstrate that it has sufficiently implemented the expected characteristics that are set for that level. Participating utilities each grade themselves, without any independent audit or verification.

SGMM Benefits

Applying the SGMM process yields numerous benefits to POUs and this overall Project. Some of the key benefits include the development of an enterprise-wide Smart Grid vision and mission, active participation and coordination across numerous utility departments and setting objective and quantifiable steps to measurement progress. These benefits are described in greater detail in Appendix A.

SGMM Domains

An SGMM assessment provides a maturity rating for each of the model's eight domains, which are listed below and described in greater detail in Appendix A.

- Strategy, Management, and Regulatory (SMR)
- Organization and Structure (OS)
- Grid Operations (GO)
- Work and Asset Management (WAM)
- Technology (TECH)
- Customer (CUST)
- Value Chain Integration (VCI)
- Societal and Environmental (SE)

Expected and Informative Characteristics

SGMM domains are built upon expected and informative characteristics. Expected characteristics are the capabilities that a POU must implement or exhibit to achieve the corresponding maturity level within a domain. For a POU to achieve Level 2 in a given domain, it must sufficiently implement the expected characteristics for both Level 1 and Level 2 in that domain. Each expected characteristic in the SGMM corresponds to a single question in the SGMM. The SGMM uses a simple labeling system to uniquely identify each expected characteristic in the model.

Informative characteristics provide additional descriptive material that provides insight into whether a POU has achieved a given level of maturity within a domain, such as its potential features or additional explanatory information. These characteristics are not used to evaluate whether a POU has achieved a specific level of maturity. Informative characteristics are not required features, so within a given domain, at a given maturity level, the SGMM may have only expected characteristics and no informative characteristics.

Domain Summary

The preceding discussion notes that each domain serves a special purpose in measuring Smart Grid attributes. Grouping the above domains into the following categories is used later in this report to better illustrate POU's Smart Grid progress and areas that require additional consideration.

- Objectives: Why is the POU implementing Smart Grid? Motives are assessed by the Strategy, Management and Regulatory and Societal and Environmental domains.
- Methodology and Applications: How will the POU achieve Smart Grid objectives? Methods and applications are primarily addressed in the Grid Optimization, Work and Asset Management, Technology and Value Chain Integration domains.

- Stakeholders: Who are the POU's internal and external Smart Grid stakeholders? This question is examined in the Organization and Structure and Customer domains.

Levels of Smart Grid Maturity

The SGMM uses six levels of maturity to define a utility's progress in implementing Smart Grid. Each maturity level represents a defined stage, which is described in terms of organizational capabilities and characteristics of the organization's progress toward achieving its Smart Grid vision. The lowest maturity level in the SGMM is 0, which represents the default, status quo or entry point in the model. It describes a case where the POU is operating a traditional, analog or non-modernized grid. As the POU begins to implement and integrate the various changes that are consistent with a modernized grid, the POU's maturity rating is elevated across one or more domains.

To achieve a specific level within each domain, the POU must demonstrate that it has sufficiently implemented the expected characteristics that the SEI defined for that level in that domain. While a POU receives a specific level rating for each domain, it may possess some characteristics associated with higher maturity levels. In practice, this is commonly the case.

It is important to keep in mind that each domain is measured uniquely, and that it is entirely likely that a POU could be relatively advanced (as indicated by a high level of maturity) in one domain while being relatively basic (as indicated by a low level of maturity) in other domains.

Key attributes under consideration within each domain include the degree of automation, economic and technical efficiency, energy, cost savings, integration of alternative energy sources, improved customer empowerment, impacts on electric reliability, compliance with regulatory directives, safety, cost of service, and alignment with the enterprise's mission and vision.

A POU can establish its current maturity level by completing the SGMM and having it scored. With this baseline or starting point in mind, the POU can establish objectives for the timing and extent of its grid modernization efforts by setting different schedules for different targets. Later in this report, we provide roadmaps to help POUs develop the details needed to plan and implement those modernization efforts. Additional assessments can be completed over time to track the POU's progress toward the established objectives.

While higher levels of maturity in the model are consistent with a POU that is successfully adopting and benefiting from its grid modernization efforts, it is important for each POU to establish its own target maturity levels based on its own unique operating profile, strategy, and timeline. The six maturity levels are briefly described below, of increasing maturity.

- 0 - Default: Default level for the model.
- 1 - Initiating: Organization is taking the first implementation steps within a domain.
- 2 - Enabling: Organization is implementing features within a domain that will enable it to achieve and sustain grid modernization.

- 3 - Integrating: Organization's Smart Grid deployment within a given domain is being integrated across the organization.
- 4 - Optimizing: Organization's Smart Grid implementation within a given domain is being tuned and used to further increase organizational performance.
- 5 - Pioneering: Organization is breaking new ground and advancing the state of practice within a domain.

POU Participation

A great many California POUs were contacted and asked to participate in this project. In response, the following 13 POUs agreed to do so, as listed below.

- Alameda Municipal Power (AMP)
- Anaheim Public Utility (APU)
- Azusa Light & Water (ALW)
- Burbank Water and Power (BWP)
- Glendale Water and Power (GWP)
- Imperial Irrigation District (IID)
- Los Angeles Department of Water and Power (LADWP)
- Pasadena Water and Power (PWP)
- Riverside Public Utilities (RPU)
- Sacramento Municipal Utility District (SMUD)
- Silicon Valley Power (SVP)
- City of Palo Alto Utilities (CPAU)
- Redding Electric Utility (REU)

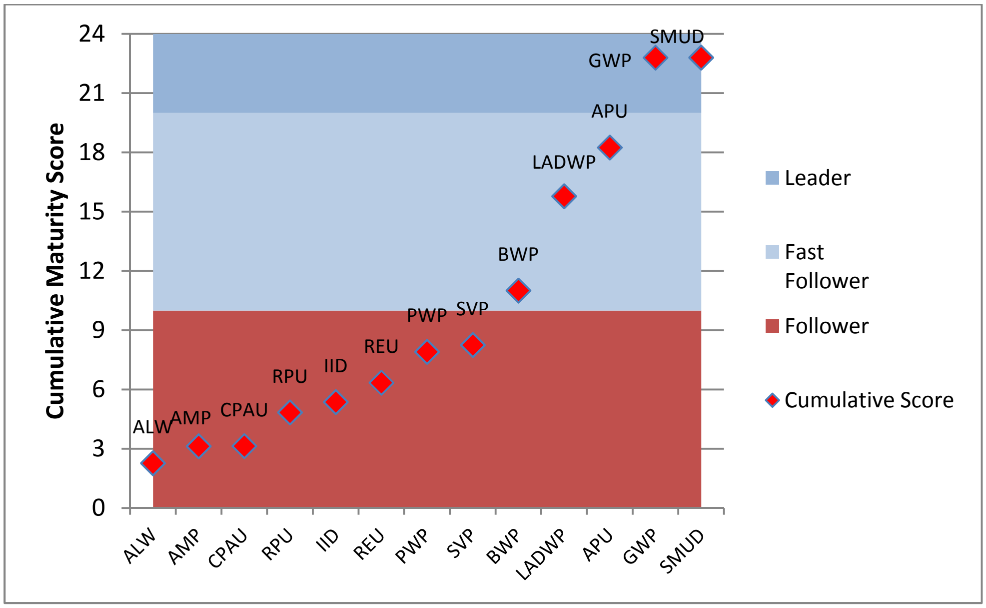
Each of the above named POUs voluntarily participated and approved of its identity and aggregate SGMM scores being noted within this report. Numerous additional POUs in California were contacted, but declined to participate.

Smart Grid Maturity Rankings and Overall Findings

Total Smart Grid maturity scores were computed for each POU as the sum of the eight individual domain scores and used to rank the POUs by the maturity of their Smart Grid programs.

Plotting the scores for all POUs is conducted to search for natural break points or groupings in the data, which could then be labeled as succinct categories for further review and understanding. The following figure is the result of that effort and depicts three distinct groupings. Break points emerge at total SGMM scores of 10 and 20. POUs that have a total SGMM score between 0 and 10 are considered to be Followers. Scores between 10 and 20 indicate that the POU is a Fast Follower and scores above 20 identify Leaders.

Figure 8: POU Smart Grid Maturity Rankings



ALW:	Azusa Light & Water	LADWP:	Los Angeles Water and Power
AMP:	Alameda Municipal Utility Power	PWP:	Pasadena Water and Power
APU:	Anaheim Public Utility	REU:	Redding Electric Utility
BWP:	Burbank Water and Power	RPU:	Riverside Public Utilities
CPAU:	City of Palo Alto Utilities	SMUD:	Sacramento Municipal Utility District
GWP:	Glendale Water and Power	SVP:	Silicon Valley Power
IID:	Imperial Irrigation District		

In addition to total maturity scores, close examination of the data gathered by the SGMM process finds that each of the three categories contains a unique set of characteristics. Understanding these characteristics is essential to identifying ways to enhance Smart Grid adoption and thereby promote the accomplishment of the Energy Commission's overarching objectives. The following discussion examines each category (Follower, Fast Follower and Leader) and presents conclusions regarding its overall position in Smart Grid adoption.

Interviews with POUs discovered that their primary areas of concern are generally focused on cost, service offerings, grid efficiency, reflections of local constituent's financial and societal concerns and clean energy job creation. The following figure summarizes such findings, with more detailed information for each of the three POU categories presented afterwards.

Figure 9: Follower, Fast Follower and Leader Characteristics

	Followers	*Fast Followers*	*Leaders*
Lower overall system cost	Reduce	Maintain	Increase
Enhance serviced offerings	Maintain	Explore	Enhance
Improve grid efficiency and reliability	Maintain	Improve	Improve
Reflect local financial, environmental and social priorities	React	Explore	Shape
Support clean energy job creation	React	Explore	Create

Followers

Overall Smart Grid Status

The third tier, Followers, is the most common category and is composed of eight POUs (SVP, PWP, REU, IID, RPU, CPAU, AMP and ALW). Followers have maturity scores that are noticeably lower than Fast Followers or Leaders. Domain levels for Followers range between 0 and 1, indicating an Initiator status within the SGMM framework. The primary characteristics of Followers are that they track the progress of Smart Grid at other POUs, especially Leaders, and monitor the overall state of the industry. Followers are generally not enabling or implementing features within a domain that are necessary to achieve grid modernization. They are also not establishing specific Smart Grid budgets, integrating or deploying Smart Grid in any of the measured domains. They have not made significant progress in launching Smart Grid pilots and their average SGMM score is less than or equal to 1. Smart Grid budgets, internal organizations and staffing are less defined than that of Leaders or Fast Followers. In some cases, Followers might not have the support of internal upper management or their Board of Directors to significantly pursue a Smart Grid program.

Lower Overall System Costs

In general, Followers are highly risk adverse and are reluctant to take any significant steps forward until all potential risks are fully understood and mitigated. This posture is especially observed in their outlook on costs. Followers are primarily concerned about ways to reduce overall capital and operating costs and may be reluctant to voluntarily implement any Smart Grid applications which are perceived to be contrary to this financial objective.

Enhance Service Offerings

Followers do not perceive the need to expand their existing service offerings. The focus is on maintaining existing services. And, some utilities in this category have made a conscious decision not to make customer service offerings based on smart grid technologies as they found it not economical to do so.

Grid Efficiency and Reliability

Grid efficiency and reliability are important to Followers, yet, improvements through Smart Grid applications are not considered to be cost effective.

Reflect Local Financial, Environmental and Social Priorities

The POU governance model provides for an effective means for consumers to voice their concerns about their local electricity provider. Followers generally respond to constituents' concerns by adhering to local preferences and mirror local opinions regarding financial, environmental and social issues. Followers react to the directives of their communities.

Support Clean Energy Job Creation

Followers are sensitive to the prevailing economic climate, especially with regard to local employment. Followers perceive their responsibilities as being focused on supporting the local community in economic development, but do not take a leadership position.

Fast Followers

Overall Smart Grid Status

POUs scoring in the second tier are APU, LADWP and BWP, which are considered to be Fast Followers. These entities have or are developing a Smart Grid vision and are expected to launch pilots to test various aspects of their proposed Smart Grid programs. Fast Followers generally have Smart Grid specific budgets and internal teams in place to support Smart Grid. Fast Followers are tracking the progress of Leaders and are carefully assessing their successes and failures with the intent to pursue the most beneficial applications. They are cautious, yet are expected to advance more rapidly once key uncertainties are resolved.

Like Followers, Fast Followers are also tracking the industry, especially within California. Though, a key difference is that Fast Followers generally perceive the primary benefits and issues of Smart Grid as being greater than just cost/benefit analysis. Fast Followers are also exploring the launch of new services, improvements to reliability, and have a heightened appreciation for potential societal and environmental benefits. Fast Followers have developed a Smart Grid business case, and either have engaged in conducting selected demonstration or pilot projects or are expected to do so in the future to test certain strategies and technologies. Fast Followers have approved budgets for Smart Grid adoptions and have received support of their upper managers and boards.

Lower Overall System Costs

Fast Followers recognize potential Smart Grid benefits and costs and are searching for a compromise, whereby certain Smart Grid attributes may be implemented while keeping their costs relatively constant. In general, Fast Followers are financially cautious, but are willing to advance new applications when the forecasted benefits outweigh expected costs. Fast Followers are primarily concerned about ways to maintain overall capital and operating costs and plan to capture Smart Grid's "low lying fruit"; such as AMR or AMI.

Enhance Service Offerings

Fast Followers are exploring the opportunity to expand their existing service offerings, but are cautious to do so without the full support of their internal management team and Board. Studies may be performed to assess the benefits and costs of new Smart Grid related services and, in some instances, certain pilot programs may be planned. Fast Followers have not launched such services.

Grid Efficiency and Reliability

Fast Followers invest time and capital into proven programs that improve the efficiency of the grid. There is a strong focus on the reliability of customer service and data is routinely gathered to monitor reliability. Fast Followers often have reliability targets.

Reflect Local Financial, Environmental and Social Priorities

Like Followers, the POU governance model provides Fast Followers' consumers with a means to voice their concerns about their local electricity provider. However, unlike Followers, Fast Followers often take a more proactive stance and explore ways to affect local financial, environmental and social programs. In some instances, Fast Followers lead their communities.

Support Clean Energy Job Creation

Fast Followers monitor the prevailing economic climate and explore ways to participate in its advancement, especially with regard to local employment. Fast Followers perceive their responsibilities as being focused on taking actions to supporting the local community in economic development.

Leaders

Overall Smart Grid Status

The above figure indicates that SMUD and GWP scored highest in overall Smart Grid maturity, visually appearing to be noticeably ahead of all other measured POUs and are therefore considered to be Leaders. The characteristics that set Leaders apart from other POUs is that they have made considerable progress in nearly all of the individual Smart Grid domains and have a noticeably higher average and total maturity score (greater than 2.7 and 20.0, respectively). Key domain level characteristics of Leaders include a well defined Smart Grid vision, mission and strategies (SMR), the development of an organizational structure that is highly supportive of Smart Grid (OS) and plans are in place that extend beyond the piloting phases (TECH, GO, CUST or VCI). They also reflect a heightened awareness of the societal and environmental benefits and considerations that accompany Smart Grid. Having a comprehensive or fully operational Smart Grid program in place is not required to be a Leader. Though, each Leader has the internal management support, plans and budgets in place to achieve a fully operational Smart Grid program by the year 2020. It is also not necessary to achieve a rating of "5" to be a Leader. This is due, in part, to the fact that Smart Grid systems are still relatively new throughout the U.S. and that available technologies, processes and standards are still being developed.

POU Leaders reflect the most mature category and have taken certain key steps forward. Leaders recognize that costs might increase to capture other priorities, such as enhanced service offerings, improvements in reliability and enabling the customer experience by providing new controls. Pilot or demonstration projects have been planned and are expected to produce meaningful results to guide future efforts.

To become a Leader, it is not necessary to be a Pioneer in Smart Grid. In practice, a POU can achieve a robust and fully deployed Smart Grid program that prudently captures the desired benefits of the individual POU without breaking new ground and advancing the industry-wide state of practice, which is the earmark of a Pioneer.

Lower Overall System Costs

Leaders implement Smart Grid programs that increase short-term costs with the objective of promoting new services or capturing qualitative benefits. Leaders assess potential Smart Grid benefits and costs, but do not limit themselves only to programs that have a short-term pay-off. Leaders are financially responsible and are willing to prudently advance new applications and services. They are aware of short-term increases in costs, but do so with an eye on longer-term benefits. Leaders do not limit Smart Grid applications to "low lying fruit" .

Enhance Service Offerings

Leaders explore opportunities to expand existing service offerings and have the support of their internal management team and Board. Studies are performed to assess the benefits and costs of new Smart Grid related services and often plan or launch pilot programs.

Grid Efficiency and Reliability

Leaders invest time and capital in ways to improve the efficiency of the grid. There is a strong focus on the reliability of customer service and specific Smart Grid applications have been identified to increase efficiency and reliability. It is commonplace for Leaders to have reliability targets.

Reflect Local Financial, Environmental and Social Priorities

Leaders take a proactive role in shaping their communities' financial, environmental and social priorities. Their local communities expect the POU to take a leadership role in environmental and social programs.

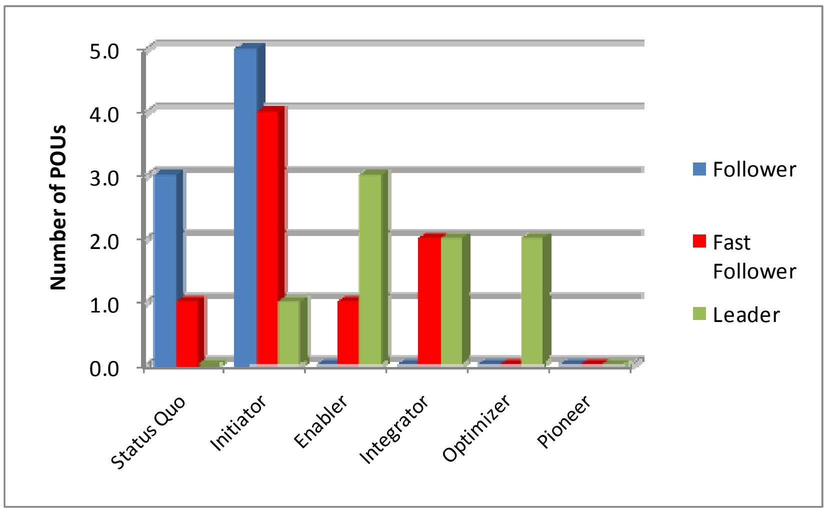
Support Clean Energy Job Creation

Leaders create Smart Grid programs that promote clean energy job creation. In some cases, this reflects a willingness to accept a certain amount of financial and technological risk as such Smart Grid programs are not widely tested and hypothetical changes in technologies could lead to obsolescence.

Comparisons between Followers, Fast Followers and Leaders

The measured Smart Grid domains for Followers are shown below to be either Status Quo (indicating that no substantial progress has been made) or Initiator (indicating that only initial progress or understanding has commenced). This is significantly different from Fast Followers, where one domain has moved up to being an Enabler (indicating that Smart Grid results are being actively used) and two domains advanced to being Integrators (Smart Grid deployment is being integrated across the organization). The shift forward is increasingly pronounced for Leaders, where two domains achieved an Optimizer status (Smart Grid implementation is used to increase organizational performance

Figure 10: Smart Grid Maturity by Category



Opportunities to Promote Smart Grid Adoption

The preceding discussion provides a basis for understanding the characteristics of three categories of POU Smart Grid status (Follower, Fast Follower and Leader). The next step is to build upon that understanding to identify the obstacles that inhibit Smart Grid progress and make recommendations for change.

How can the Energy Commission serve as a catalyst to Smart Grid adoption by Followers?

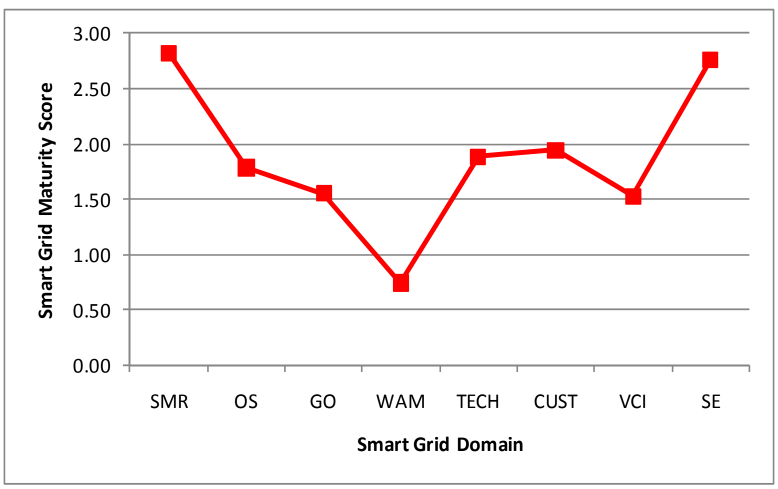
The most commonly cited obstacles that inhibit Smart Grid developments among Followers are economic (such as, high capital costs) and management/Board directives. Followers need to perceive a favorable cost/benefit analysis to justify required next steps, especially capital purchases for pilot test deployments. The paradox here is, however, that many Followers have not yet exercised a business case to adequately estimate costs or benefits. Such analytical shortcomings may stem from the absence of a simple, straightforward template for conducting initial Smart Grid assessments. Prevailing industry-wide research is replete with highly sophisticated frameworks for Smart Grid cost/benefit analysis. Yet, available approaches are complex and require a significant amount of detailed data that many POUs either don't readily have, routinely collect or are unable to independently estimate. Consequently, tools that fail to address the unique circumstances of POUs are expected to fall by the wayside.

To address this analytical gap, this report contains a framework for cost/benefit analysis that is designed specifically for smaller utilities. It focuses on readily available data that is "off-the-shelf", thereby embracing the implicit trade-off between being used in practice and forecast accuracy in cost/benefit results. Advocating the use of tools that enable POUs to realistically create a first cut estimate of their own costs and benefits would promote the adoption of Smart Grid at utilities where progress is currently stalled.

How can the Energy Commission serve as a catalyst to Smart Grid adoption by Fast Followers?

Fast Followers also confront challenges that inhibit Smart Grid adoption. Interviews with POUs discovered that they are commonly engaged in the overall process and are now in the early stages of planning test pilots. From a domain perspective, Smart Grid maturity varies greatly and the scores for the average Fast Follower are shown in the following figure.

Figure 11: Fast Followers' Average Maturity Score by Domain



SMR:	Strategy, Management, and Regulatory Domain	TECH:	Technology Domain
OS:	Organization and Structure Domain	CUST:	Customer Domain
GO:	Grid Operations Domain	VCI:	Value Chain Integration Domain
WAM:	Work and Asset Management Domain	SE:	Societal and Environmental Domain

The above figure indicates that the WAM domain is significantly lagging behind other domains and is, therefore, the focal point of promoting Smart Grid among Fast Followers. WAM focuses on improvements to the management of human and physical assets to improve electric reliability, reduce maintenance downtown, increase outage tracking and reporting on the causes of failures, improved fault diagnosis, detection of failure conditions in advance of actual failures. These tasks cannot adequately take place without certain underlying ingredients, including:

System Monitoring and Reporting: Maximizing the utilization of distribution apparatus (such as, asset management of transformers, poles, cable, and so forth.) requires monitoring and reporting of loading and event data over a sufficient period of time to build a meaningful historical database. During the early stages of Smart Grid deployment, sufficient data will not be available and asset management may be compromised. The Energy Commission can take an active role in addressing this issue by working with POUs to conduct industry research to create proxies for historical equipment loadings. It should be noted that advanced metering infrastructure (AMI) can enable equipment monitoring and reporting, but is not necessary for building historical databases.

Geographic Information System (GIS) Interfaces: An advanced stage of WAM implementation integrates system monitoring and reporting with GIS. Most POUs have some form of GIS in place today, though fewer have integrated mapping functions with asset inventory data.

Business Processes and Back Office Systems: Certain back office systems will be required to fully enable WAM. Today, most Fast Followers have business processes that are asset centric and are not focused on asset functionality. More advanced WAM operations will enable improved work order scheduling and recording.

Overall, the Energy Commission's role in promoting WAM may be relatively minor. However, the above noted assistance in developing surrogate equipment loading models will be valuable.

How can the Energy Commission serve as a catalyst to Smart Grid adoption by Leaders?

Leaders, by definition, represent the most mature Smart Grid programs of any of the POUs. While such progress is laudable, challenges will persist and future challenges are possible. Key challenges include:

Commitment: Results from pilot projects will be collected and studied in the future to guide Leader's next steps. While the forecasted outcomes of such pilots are optimistic, actual results might identify certain challenges and obstacles. Leaders will need to be fully committed to the implementation process to work through such matters, despite the hypothetical need for higher than anticipated capital or human resources or adverse public perceptions. Since Smart Grid remains a nascent enterprise, the road ahead is, to some degree, uncertain and Leaders have few examples to follow.

Decision Making and Economic Justification: Upon the completion of Smart Grid pilots, Leaders will face decisions regarding which specific Smart Grid applications should be implemented. The decision making process could, hypothetically, follow multiple paths. A holistic approach would assess the costs, benefits and other attributes on the basis of an entire Smart Grid program. In contrast, decision making could follow a path of incremental cost/benefit ("low lying fruit"), whereby a POU might first implement those Smart Grid applications that produce the highest benefit/cost ratio. Subsequent Smart Grid additions, while valuable, might be avoided due to their incremental costs being greater than their incremental benefits. This dilemma is expected to confront all POUs, and not just Leaders.

However, since Leaders are chronologically ahead of all other POUs, they may be the first ones to exhibit the issue.

An important role that the Energy Commission can play in promoting Smart Grid for Leaders (and other POUs as well) is to facilitate utility forums for the purpose of cross-pollenization of results. Such forums could include a utilities-only session where POUs and IOUs could informally share Smart Grid information on a one-on-one basis.

Utility Comparisons

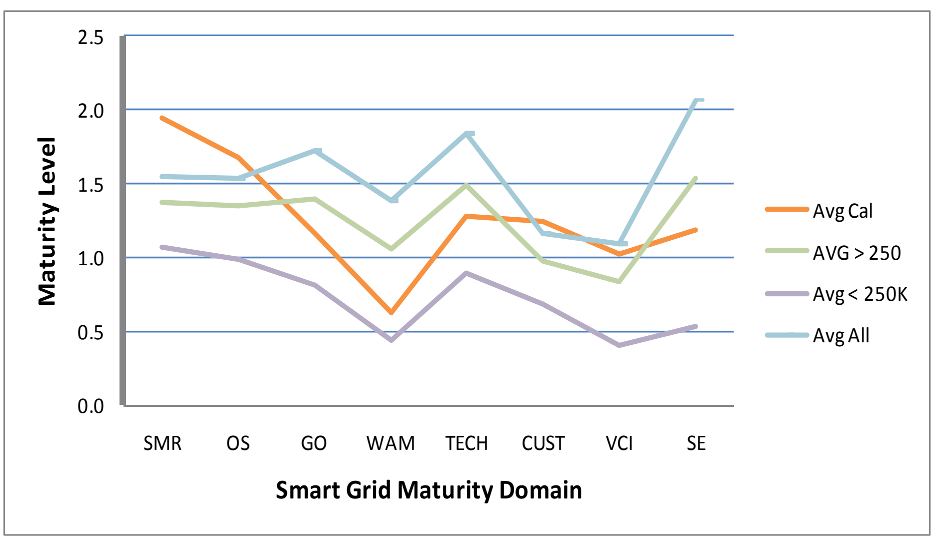
An important objective of this project is to compare the maturity of Smart Grid across California's POUs and between the POUs and other utilities. Again, the SGMM was used as the basis for this assessment and selected results are already noted above. Multiple categories of utilities were constructed for the purposes of making comparisons.

- California POUs with fewer than 250,000 meters
- California POUs with more than 250,000 meters
- All California POUs
- All U.S. utilities (investor and publically owned)

Overall, this project found that the Smart Grid programs of larger California POUs are more mature than their smaller counter parts. This observation is not surprising and is likely to be a function of the human and capital resources that are required to study, plan and implement Smart Grid. To illustrate, the two largest POUs (SMUD and LADWP) are also among the four most mature entities surveyed.

Data for small and large California POUs are shown in the following figure.

Figure 12: Maturity Level by Domain for Small and Large California Utilities and the U.S.



SMR: Strategy, Management, and Regulatory Domain TECH: Technology Domain

OS:	Organization and Structure Domain	CUST:	Customer Domain
GO:	Grid Operations Domain	VCI:	Value Chain Integration Domain
WAM:	Work and Asset Management Domain	SE:	Societal and Environmental Domain

Conclusions drawn from comparisons between California and the rest of U.S. are less straightforward. For most domains, California's POUs scored at a slightly lower maturity level than utilities located outside of California. The one exception is SMR, in which the maturity of California POUs is more advanced. However, the significance of these differences, whether higher or lower, is called into question. In the context of SGMM, scores are effectively an integer measure and there is no difference between (for example) a maturity score of 0.7 and 1.6. Both hypothetical utilities are considered to be "Integrating." With this in mind, there are only two domains (WAM and SE) where California's POU lag behind the rest of the nation. All other domains were equally graded.

The key question here is then whether and how the Energy Commission can leverage these results to better promote Smart Grid adoption within California and the accomplishment of California's Energy Policies. It is recommended that the Energy Commission take a more active role in the national debate on Smart Grid and serve as a conduit of information between other state's utility and energy commissions and the POUs.

SGMM Applications to Identify Vision 2020

This project included a series of follow-up workshops with POUs that provided a two-way dialogue on the results of their own SGMM status, and, to collaboratively assess where each POU should be in its Smart Grid program by the year 2020. Status findings included each POU's current maturity in each of the eight SGMM domains and comparative statistics from the other POUs that completed the survey.

The second part of the workshop focused on establishing aspirations for future Smart Grid developments, as measured by their forecasted SGMM maturity ratings. The aspirations workshop provided essential information to the POU's strategic planning process. It cut across numerous POU departments, provided a forum for expressing the needs and concerns of each department, heightened awareness of affected functional areas and, in some cases, enabled the POU's only cross-management level Smart Grid planning sessions.

The specific components of the aspirations workshop included:

- Motivations: What are the high-level Smart Grid related objectives that the POU wants to accomplish? Most POU responses fall into one of the following categories: reduce costs to consumers, improve reliability, improve operational efficiency, empower customer choice and control, address societal/environmental objectives and adhere to regulatory/board directives. These motivations are not mutually exclusive and there are instances where a particular action touches upon multiple categories.

- Actions: What tasks does the POU need to complete to achieve the above motivations? POU responses generally spanned the entire list of 175 separate questions contained in the SGMM, including: completion and enterprise-wide communication of a coherent

Smart Grid mission, increased investments, estimate costs and benefits, identify technological risks, education (staff, stakeholder and board),

- Obstacles: What obstacles inhibit a POU from accomplishing the above tasks or motivations? Common POU responses included short-term and project life-cycle capital requirements, human resource requirements (including training), management/board support, risk adversity, cyber security and the lack of industry-wide standards.

Outcomes of the aspirations workshops for each POU are summarized below.

Table 4: Summary of Motivations, Actions and Obstacles

SGMM Domain	Summary of Motivations	Summary of Actions	Summary of Obstacles
SMR	Have an enterprise-wide vision for Smart Grid Ensure that the Smart Grid vision aligns with the utility vision Meet customer expectations Adhere to regulatory mandates Reduced cost to consumers Improved reliability of service Maintain or improve customer and employee safety Empower customer choice Improve technical efficiencies Offer alternative rates Economic development and job creation Corporate desire to be a Pioneer in Smart Grid Create new sources of revenue	Create and communicate a utility-wide vision for Smart Grid Create an internal Smart Grid team Create a common definition for Smart Grid for the board, management team, staff and consumers Obtain buy-in from the board, management, employees and stakeholders Encourage enterprise-wide participation Complete a Smart Grid business case (such as, define objectives, identify services, and estimate costs and benefits) Educate the board and staff Obtain approval for Smart Grid specific budgets	Capital resources Human resources Board and management support Regulatory uncertainty Consumers' acceptance of higher rates Consumers' perception of value of various services Consumer participation Lack of industry definition of vision and benefit Smart Grid competes with other priorities Economic uncertainty
OS	Embrace a Smart Grid driven organizational culture Use Smart Grid initiatives to drive new strategies Cross department boundaries to capture benefits Build internal Smart Grid competencies (training)	Management needs to lead cultural changes Adopt vision, goals and strategy Implement an organizational structure around Smart Grid vision and goals Acquire new human resources (hiring) Assess the organizational structure Educate upper management (Mayor, council, and so forth.) Enact decision making at the closest point of need	Capital resources Human resources Cultural inertia Staff's willingness to be trained Change management Access to training and educational materials Ongoing commitment and willingness to work through problems

SGMM Domain	Summary of Motivations	Summary of Actions	Summary of Obstacles
GO	Increased reliability Reduce operating costs Increase system efficiency and pre-failure awareness Improved system modeling and forecasting Enable event based load forecasting Peak and load leveling Outage management Integration of renewable resources Power quality Minimize brown-outs	Achieve pre-event awareness Implement pre-event proactive corrections (fix before it fails) Appropriate funds Installation of AMI and other infrastructure (sensors) Develop new operating schema to realize benefits Train or hire key workforce Implement substation automation	Capital resources Adequate communications (bandwidth, latency and reliability) Technical obsolescence Hiring constraints Integration of third party assets (distribution with transmission and generation) Integration of distributed and renewable generation System protection and concerns for safety Lack of IT strategic plan to support GO Standards remain a moving target
WAM	Improve asset management Improve work order control and management Increased accuracy in project cost estimating Maintain high degree of cyber security Reduce operating and maintenance costs Improve reliability Enhance asset life Reduce truck rolls	Invest in workforce automation Integrate work order, asset and GIS Implement condition based maintenance Automate asset inventory and tracking Implement remote asset monitoring Develop a mobile workforce strategy Develop a baseline of failures, events, loadings and lifecycle costs Complete fleet inventory	Economic justification Capital resources Human resources Workforce training Inertia to cultural change
TECH	Create a culture of utility and customer data security Enable Smart Grid applications Achieve end-to-end system integration Achieve an adequate communications network (bandwidth, latency, reliability and footprint) Adhere to NERC-CIP standards regarding security and critical infrastructure Standards selection	Create a comprehensive IT vision and strategy plan that supports anticipated Smart Grid applications Create communications vision and strategy Assess IT compatibility with Smart Grid vision (identify gaps)	Cyber security is an on-going process and requires continued support Lack of comprehensive IT vision and role in Smart Grid Capital resources Maintaining sufficient human resources Adherence to NERC-CIP standards and compliance Privacy of customer data Integrating IT into cross-functional decision making Technology lifespan Technology standards

SGMM Domain	Summary of Motivations	Summary of Actions	Summary of Obstacles
CUST	Maintain a customer centric focus Meet customer expectations Empower customer decision making Provide customers with new services Provide options for new rates (real-time rates) Outage management Reduce lost revenue (theft)	Educate customers Clarity of vision and capabilities Pilot projects and proofs of concept Deployment of AMI Complete Billing and IT integration Enable remote connect/disconnect capabilities Enable on-demand usage data Enable outage detection and proactive notification Achieve and maintain customer participation Provide an automated response to pricing signals	Customer education On-going customer participation Staffing and organizational support Existing rates programs Customer resistance to Tiered rates and services In-house help desk Staff training Economic justification
VCI	Achieve least-cost pricing Achieve buy-in from stakeholders Regulatory requirements Target new resources and technologies Lower costs (both retail and supply side) Increase system reliability Supply-side management Achieve portfolio standards (such as, increased integration of renewable resources) Increased fuel diversity Reduce environmental (carbon) impact Avoid or delay conventional generation additions Make energy resources dispatchable and tradable	Enable customer premise energy management with market and usage information Offer two-way HAN to residential customers Achieve large appliance visibility and control Enable behind the meter generation (roof top solar) Launch, monitor and complete pilot projects Provide for home energy management systems	Reduced revenue from reduced use On-going customer participation Value chain partner participation Capital resources Cyber security
SE	Adhere to regulatory requirements Meet customers' expectations Participate in green initiatives Reduce GHG Adhere to carbon caps Achieve sustainability (triple-bottom-line) Commitment to portfolio management	Achieve enterprise-wide commitment and participation Ongoing monitoring and measurement Obtain board and management vision and strategy Share status data with stakeholders Offer energy efficiency programs Create performance measures	Ongoing customer participation Capital requirements Ongoing political support Internal cultural inertia Balance conflicting goals among different stakeholders Skepticism of benefits and claims Moving targets

SGMM Domain	Summary of Motivations	Summary of Actions	Summary of Obstacles
	Social responsibility Achieve Peak shaving EV integration	Perform proof of concept projects Provide customers with resource and usage data	

AMI: Advanced Metering Infrastructure
GHG: Green House Gas
GIS: Geographical Information Systems
NERC-CIP: North American Electric Reliability Corporation - Critical Infrastructure Protection
SGMM: Smart Grid Maturity Model
SMR: Strategy, Management, and Regulatory Domain
OS: Organization and Structure Domain
GO: Grid Operations Domain
WAM: Work and Asset Management Domain
HAN: Home Area Network
IT: Information Technology
TECH: Technology Domain
CUST: Customer Domain
VCI: Value Chain Integration Domain
SE: Societal and Environmental Domain

Smart Grid Gaps

The preceding discussion outlines numerous motives, actions and obstacles that excite, yet also inhibit POUs' efforts toward a more robust Smart Grid implementation. More importantly, a close examination of these data finds that certain issues are being mentioned quite often. To summarize:

Capital Resources: POUs' access to financial resources is limited and their capital budgets are subject to the scrutiny of ratepayers. Prevailing economic conditions are causing POU customers to be increasingly concerned about electric rates and may therefore be cautious about approving their electric suppliers' engagement in new technologies. This is especially true since the benefits and costs are relatively unproven.

Human Resources and Education: POUs generally have fewer staff than IOUs. This impedes capturing any economies of scale that might be available in applying specialized staff to the advent of new Smart Grid applications. Existing POU staff requires in-depth training to be better prepared to plan, install and operate Smart Grid applications.

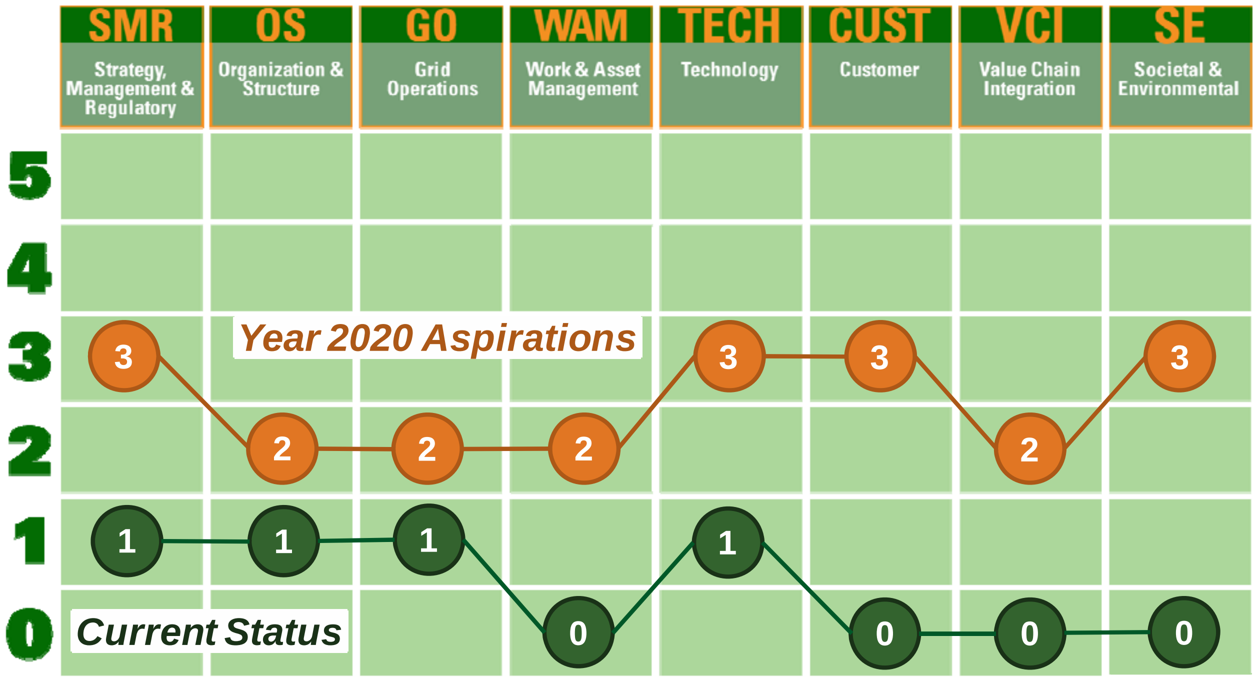
Customer Participation: One of the pervasive issues that faces a successful Smart Grid launch is the role of customers. Many of the financial benefits that Smart Grid offers may not be fully realized if customers are not adequately engaged and participate on an on-going basis. Once the newness of the offering (such as, home area networks) has faded, customers might lose interest and revert to traditional behaviors.

Cyber Security and Data Privacy: The implementation of Smart Grid in some California communities has raised questions about the security of utility networks and the privacy of customer data. Cyber security is a process and not an end-point. Therefore, POUs will need to make an ongoing investment in their IT processes and staff to ensure that adequate safeguards are in place and updated.

Uncertainty: POUs are confronted with making decisions in the face of uncertainty. For example, planning a Smart Grid program begins with the development of a business case that is founded upon costs and benefits which are estimates, and not based on years of factual data.

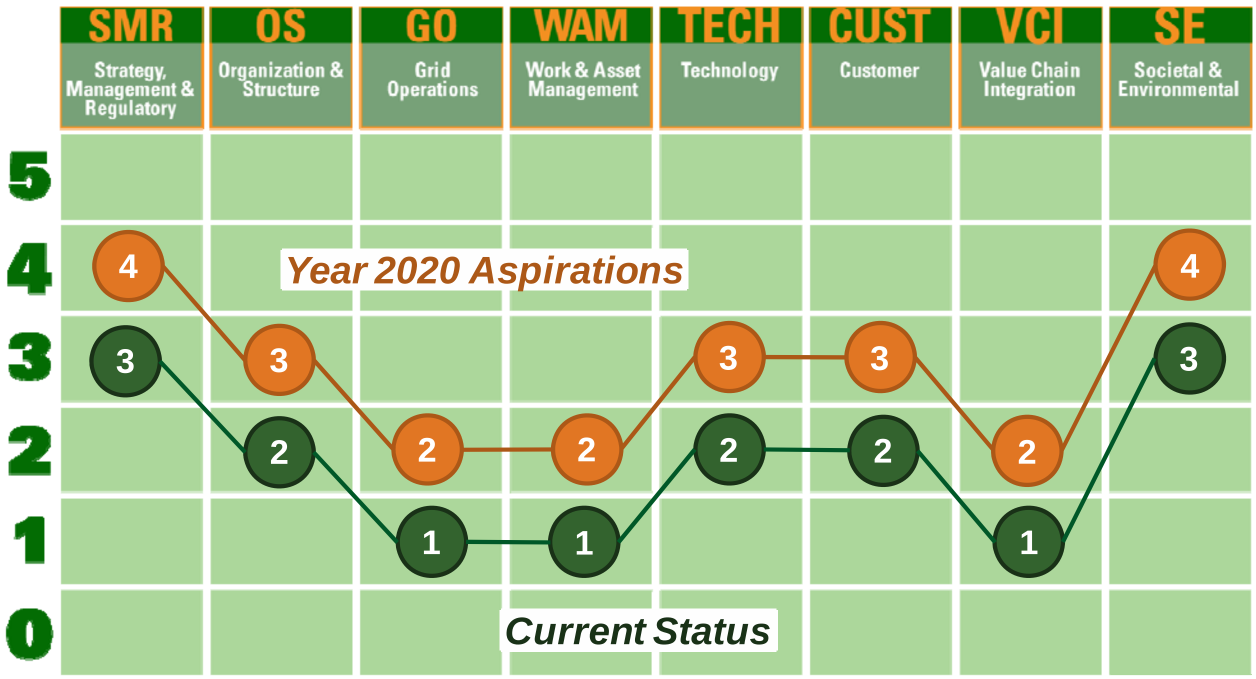
Regulatory agencies continue to grapple with policies that affect the choice of Smart Grid applications and services. Standards are evolving and may be unsettled for years to come. Collectively, uncertainties raise the barrier to Smart Grid adoption. This is especially important in the POU space as the prevailing posture is to be risk adverse.

Figure 13: Followers' Current Status and Year 2020 Aspirations



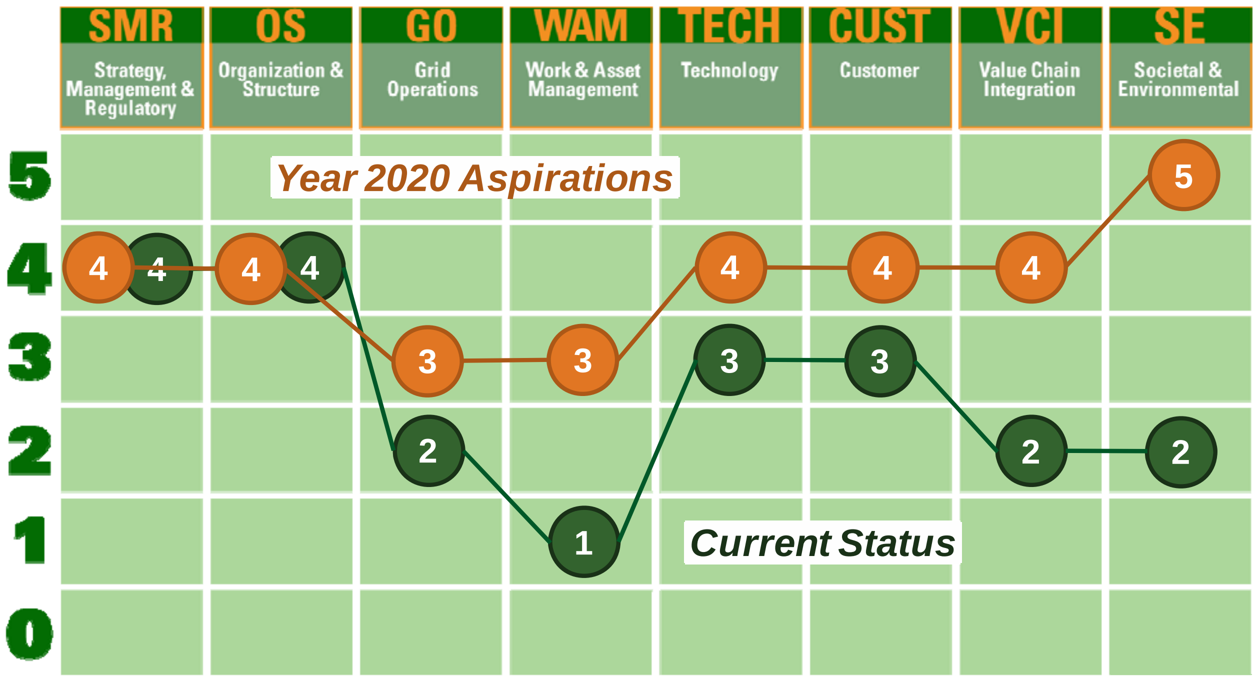
The above figure suggests that Followers are generally concerned about advancing the maturity of their Smart Grid systems, though remain cautious about its future aspirations. The current status is either a 0 or 1 and is expected to advance to either a 2 or 3 by the year 2020. The most significant growth is found in the Customer domain, indicating a noticeable emphasis on the role that POU's play in the development of a Smart Grid

Figure 16: Fast Followers' Current Status and Year 2020 Aspirations



In contrast to Followers, the current status of Smart Grid among Fast Followers is more mature and future aspirations are expected to reflect an ongoing evolutionary process through the year 2020. Large increases in domain maturity are not observed, yet there is uniform improvement across all domains.

Figure 17: Leaders Current Status and Year 2020 Aspirations



The year 2020 aspirations of Leaders are significantly different than Followers or Fast Followers. The evolutionary process that was observed for Fast Followers is expected to be nearly complete and the primary focus shifts away from broad improvements to more focused efforts in selected domains. Little progress is anticipated in the SMR and OS domains, as they are already highly mature. Instead, progress is directed toward the WAM, VCI and SE domains, which current lag other areas. Leaders anticipate achieving a maturity level of 5 in SE, which is the only domain to receive this score.

POU Aspiration Summary

The above figures denote the aspirations of the POUs to increase the maturity of their existing Smart Grid programs. These data are summarized in the following table and indicates that, overall, most POUs expect to reach a maturity level of 2 (Enabler) or 3 (Integrator) by the year 2020. This reflects an improvement from their current status. For example, the average SMR maturity is currently scored as 1.95, while most POUs aspire to be 2 to 4 in the year 2020.

Table 5: POU Year 2020 Aspirations by Domain

Aspiration Level	SMR	OS	GO	WAM	TECH	CUST	VCI	SE
5	1	1	0	0	0	2	1	3
4	4	2	0	0	5	4	3	2
3	5	3	8	7	4	4	3	5
2	2	6	3	3	2	2	2	1
1	1	1	2	3	2	1	4	2
0	0	0	0	0	0	0	0	0
Current Average	1.95	1.67	1.16	0.63	1.28	1.24	1.02	1.19

SMR: Strategy, Management, and Regulatory Domain
OS: Organization and Structure Domain
GO: Grid Operations Domain
WAM: Work and Asset Management Domain
TECH: Technology Domain
CUST: Customer Domain
VCI: Value Chain Integration Domain
SE: Societal and Environmental Domain

The following table quantifies how aggressive the aspirations are relative to the POUs' current maturity rating by calculating the number of levels that each POU expects to traverse. These data indicate that, in general, POU's expect to move up one to three maturity levels between the years 2011 and 2020.

Table 6: Changes in Domain Levels

	SMR	OS	GO	WAM	TECH	CUST	VCI	SE	Total
Move up 5 levels	0	0	0	0	0	0	0	0	0
Move up 4 levels	0	0	0	0	0	2	1	2	5
Move up 3 levels	2	0	3	4	3	5	1	4	22
Move up 2 levels	4	5	4	4	5	1	6	3	32
Move up 1 levels	6	5	2	4	5	4	4	4	34
Move up 0 levels	1	3	4	1	0	1	1	0	11

SMR: Strategy, Management, and Regulatory Domain
OS: Organization and Structure Domain
GO: Grid Operations Domain
WAM: Work and Asset Management Domain
TECH: Technology Domain
CUST: Customer Domain
VCI: Value Chain Integration Domain
SE: Societal and Environmental Domain

Future Research

The following areas would benefit from further research. Specific items include:

- Ongoing Smart Grid Tracking and Monitoring: Tracking SGMM is demonstrated to provide insight into the status of Smart Grid development at POUs. Since it is a measurement at a single point in time, tracking the POU's progress over time and timely success in achieving future aspirations, it is recommended that the Energy Commission support the application of SGMM at two-year intervals through the year 2020.

- Future SGMM Development: The SGMM is a powerful tool, yet has certain areas where refinement is recommended to track the unique needs and circumstances of POUs. Specific examples include survey question modifications to reflect POU governance (POUs are not regulated in the same manner as IOUs), concept of the utility's grid (the POU's grid is predominantly a distribution system, yet some SGMM questions pertain to the transmission or generation systems), and services (many POUs offer water and natural gas in addition to electricity – SGMM questions do not account for economies of scope that may be available by addressing multiple services).
- Unique POU Challenges: POU's face certain challenges that are significantly different from IOUs. Consequently, it is not surprising to find that the Energy Commission's role in promoting Smart Grid in the POU space needs to take into account a different set of challenges. Specific examples include size (POUs are commonly smaller than IOUs and therefore have fewer human resources to draw upon in implementing a Smart Grid program), financing (POUs' access to capital is significantly different from IOUs) and governance (POUs need to be responsive to an elected board which reflects the interests of its ratepayers).
- Scalability: Costs associated with many, necessary Smart Grid functions are not well scalable. Regardless of size, utilities are expected to require specialized expertise in cyber security, back-office support and software, communications and management. To a large extent, these features disadvantage smaller utilities (most notably POUs) and adversely affect the economic justification of Smart Grid. It is recommended that the Energy Commission support research into scaling Smart Grid systems to better fit smaller utilities.
- Transmission: POUs generally fall into two groups; those that own and operate transmission systems (such as, IID, LADWP and SMUD) and those that rely on third parties (such as, joint agencies such as the Southern California Public Power Authority). One Smart Grid application that has received comparatively less attention is transmission systems and sychrophasors. The role that non-transmission owners play in such areas is limited.

Current State Smart Grid Implementation Assessment

This section summarizes the current state of Smart Grid technology and application deployments by the participating POUs. In conducting the current state Smart Grid implementation assessment, SAIC relied on the SGMM survey questionnaire that each of the POUs completed, supplemental information provided by the participating POUs for the purposes of this study, publicly available information from a variety of sources (such as, smartgrid.gov, POU websites, vendor websites, published articles,…and so forth.), information collected through SGMM workshops and one-on-one meetings, and finally interviews conducted with the participating POUs.

Introduction to Current State Smart Grid Implementation Assessment Framework

The current state Smart Grid implementation assessment focuses on four strategic areas:

- **Information technology and foundational systems:** A POU's organizational capabilities and characteristics that enable effective strategic information technology and information systems (IT/IS) planning for Smart Grid capabilities are demonstrated by two important measures: The implementation of IT/IS, and the establishment of rigorous engineering and business processes for evaluation, acquisition, integration, and testing of new Smart Grid technology.
- **Customer service and demand management and response:** A POU's organizational capabilities and characteristics that enable customer participation thru the Smart Grid transformation are demonstrated by two important measures: The implementation of customer service and demand management and response related devices and technologies, and programs. Through the implementation of these technologies and programs, POUs can encourage passive or active customer participation by empowering the customers to make and execute their own choices regarding the use, source, and cost of energy, while protecting the security of the grid and customer privacy.
- **Grid automation and management:** A POU's organizational capabilities and characteristics that support the reliable, secure, safe, and efficient operation of the electrical grid are demonstrated by two important measures: The implementation of grid automation devices and technologies, and grid management systems. Through the implementation of these technologies and programs, POUs can automate often manually intensive operations and gain more visibility of real-time conditions. Thus POUs can improve reliability, security, efficiency, and safety of their electrical grid, while also optimizing usage of their grid assets, operating more efficiently and delivering high-quality power.
- **Distributed energy resources and distributed generation:** A POU's organizational capabilities and characteristics that promote conservation and green initiatives are demonstrated by two important measures: The implementation of distributed energy resources (DER) and distributed generation (DG) and technologies enabling management and integration of these resources into the POU's electrical grid. Through the integration of these resources and the use of enabling technologies, POUs can better achieve regulatory and societal goals, while still improving the reliability, security, and safety of their electrical grid and decreasing demand and power supply costs.

SAIC identified the strategic focus areas based on the commonalities of the enabling technologies needed for each Technology Use Case. The Technology Use Cases are introduced in the Executive Summary and further discussed in Chapter 4. Table 7 presents the mapping of the current state Smart Grid implementation assessment strategic focus areas to the Technology Use Cases.

Table 7: Technology Use Case Mapping

Current State Implementation Assessment Strategic Focus Areas	Technology Use Case Mapping
Information technology and foundational systems	Applicable to all Use Cases
Customer service and demand management and response	**Use Case 2** – Advanced Metering **Use Case 4** – Demand Response
Grid automation and management	**Use Case 1** – Substation Automation **Use Case 5** – Distribution Automation **Use Case 7** – Asset Management
Distributed energy resources and distributed generation	**Use Case 3** – Distributed Energy Resources

Information Technology and Foundational Systems

The aptitude for technology adoption varies greatly among the participating POUs. The factors impacting the adoption of technologies are mainly driven by availability of resources/funds needed to acquire, implement and manage new technologies, lack of technology vision and leadership, and lack of knowledge and/or confidence in new technologies.

SAIC assessed the level of deployment of foundational IS applications among the participating POUs. The foundational IS applications are not directly considered as Smart Grid technologies. However, lack of these systems or the lack of integration among these systems greatly impairs a utility's ability to in some cases implement, and in other cases make full use of, Smart Grid technologies that are in place. These foundational systems are identified below.

- **Supervisory Control and Data Acquisition (SCADA) Systems:** Comprises a master station at the utility that communicates with monitoring and control systems in substations. SCADA communication systems vary widely from private utility networks to leased lines to cellular connections. Typical data latency is under five seconds. SCADA systems typically report status of dozens of operating parameters, and provide control of basic functions such as load tap changers and switches. SCADA application is expanding rapidly now, but a typical U.S. utility has SCADA only at its major substations.
- **Geographical Information Systems (GIS):** Maintains information about the power grid, location information about grid assets, as well as capabilities and relationships between assets in a geospatial format. For example, the GIS would maintain capacitor banks

associated with a particular meter given a particular feeder configuration. GIS is critical for geographical representation of utility assets in engineering analysis and outage management applications.

- **Engineering Analysis (EA) Systems:** Provides analytical capabilities such as power flow and voltage drop modeling, reliability analysis, contingency and sectionalizing studies, short circuit and fault current calculations, protective device coordination and arc flash hazard analysis in support of distribution system planning and analysis. These systems often utilize circuit modeling software that will accurately represent a fully detailed circuit model including individual customers, inline and endpoint devices, and even distributed generation. These systems are often interfaced with GIS for more realistic geographic representation, and customer information systems, SCADA and advanced metering data sources

- **Outage Management Systems (OMS):** Maintains the status of customer outage along with managing switch orders and switch operations for planned, unplanned and emergency outages. The OMS receives information from GIS, customer information systems, advanced metering infrastructure, SCADA, and field crews. Information collected by OMS is used to calculate grid reliability and performance indices.

- **Interactive Voice Response (IVR) Systems:** An automated call handling system which coordinates communication between the utility and its customers. These systems are typically used for handling customer requests (such as meter reads, service requests, account updates and so forth.) and payments in an automated fashion. However, the value of IVR systems becomes crucial during outages. These systems are typically designed to handle large volume of phone calls for an extended period of time. Through integrations with customer information systems, these systems can automatically identify callers, retrieve customer information and log the reported outage information. Through integrations with OMS, it can provide customers with current outage information including; known outage areas, current restoration efforts and estimated time of restoration and even provide callback services.

- **Asset Management Systems (AMS):** Maintains utility asset information and standardizes utility asset identification, information and processes involved in asset management. AMS provides the accounting equivalent of a comprehensive inventory control, asset / logistics management and maintenance planning system for an electric utility. AMS improves utility's ability to meet regulatory demands for asset planning and maintenance, and better design and control over the capital expense program. In a utility environment, AMS is typically integrated with financial systems, work management systems, and GIS to streamline asset management business processes.

- **Work Management System (WMS):** Facilitates the management of construction, maintenance and operations work requests by automating and streamlining the business processes required to initiate, track, design, estimate, schedule, construct and close work requests.

- **Mobile Workforce Management Systems (MWFM):** Provides call center operators, field force managers, and dispatch teams computer resources for receiving customer/work requests, organizing the utility's responses, tracking the work as it progresses, and analyzing work performance. MWFM solutions utilize data communications, so that field staff can retrieve current information and receive updated instructions and assignments at any time in the field.
- **Energy Management Systems (EMS):** Enables operators of electric utility grids to monitor, control, and optimize the performance of the generation and/or transmission system. Typically integrated with SCADA systems for monitoring and control functions.
- **Customer Information Systems (CIS):** Maintains customer contact information, calculates and formats customer bills, receives and applies payments for individual accounts. The system is responsible for storing customer information such as site data, demographic data, meter number, rates, program participation, and billing /payment information.

Table 8 below presents the level of deployment of the foundational information systems by the participating POUs. SMUD has all the foundational systems deployed. SMUD has supervisory control and data acquisition (SCADA) system on most of its substations and is in the process of expanding its SCADA implementation to the remaining substations within the next few years. SMUD is closely followed by BWP and LADWP. BWP has eight foundational systems deployed, and is in the process of implementing an engineering analysis system. BWP is also planning to implement a mobile workforce management system within the next few years. LADWP has implemented a new SCADA system, completed a mobile workforce management strategy, and enabled mobility of its geographical information system (GIS), outage management system (OMS), work management system (WMS) and asset management system (AMS). These POUs are followed by APU and RPU.

Table 8: Deployment Level of Foundational Information Systems by POU

Information Systems	ALW	AMP	APU	BWP	CPAU	GWP	IID	LADWP	PWP	REU	RPU	SMUD	SVP
SCADA[1]	◒	◒	●	●	●	●		●	●	●	●	●	●
GIS[2]	◒	○	●	●	●		◒	●	●		●	●	●
EA[3]	○	◒	●	◒	●	●	◒	●	●		●	●	●
OMS[4]	◒	○	●	●	◒	◒		●	○			●	
IVR	●	●	●	●	●	●		●	●		●	●	●
AMS			●	●		○		●	●		●	●	
WMS[5]		○	●	●	⊙	○		●			●	●	
MWFM				○		○	○	○		○		●	
EMS				●		○						●	
CIS	●	●	●	●	●	●	●	●	●	●	●	●	●

○Planning ⊙Piloting ◒Deploying ●Deployed

ALW: Azusa Light & Water
AMP: Alameda Municipal Utility Power
AMS: Asset Management System
APU: Anaheim Public Utility
BWP: Burbank Water and Power
CIS: Customer Information System
CPAU: City of Palo Alto Utilities
EA: Engineering Analysis
EMS: Energy Management System
GIS: Geographical Information Systems
GWP: Glendale Water and Power
IID: Imperial Irrigation District
IVR: Interactive Voice Response
LADWP: Los Angeles Water and Power
MWFM: Mobile Workforce Management
OMS: Outage Management System
PWP: Pasadena Water and Power
REU: Redding Electric Utility
RPU: Riverside Public Utilities
SCADA: Supervisory Control and Data Acquisition
SMUD: Sacramento Municipal Utility District
SVP: Silicon Valley Power
WMS: Work Management System

1- Efacec Advanced Control Systems (ACS) is the most common SCADA vendor, preferred by four of the POUs. SCADA vendors selected by the other POUs include Survallent, Telvent, Open Systems International (OSI), Siemens and ABB.
2- Almost all of the POUs are using ESRI-based GIS platforms, except SMUD. SMUD is using GIS, OMS and MWFM solutions by Intergraph.
3- POUs display a great variety in their choice of EA products/vendors. SynerGee, Milsoft, EDD, NetBas, LDPro, and OSISoft are some of the observed EA vendors.
4- Most of the POUs that already have implemented or are in the process of implementing an OMS have selected the same vendor for their SCADA system as well. The preferred OMS vendors are ACS, Telvent, Survallent and Intergraph.
5- Most of the POUs who have deployed WMS are using Oracle.

The integration level achieved among the foundational systems is what determines whether a utility is achieving its objectives towards a smarter grid. The integration among these systems enables for automated, efficient, accurate and reliable information sharing among the utility's business units and operations. In return, utility is able to mitigate risks associated with missing and/or inaccurate information due to human error in manually intensive environments. Among the leaders, SMUD has achieved the highest level of integration among all its foundational systems in place. SMUD's GIS is fully integrated with other applications presenting asset, connectivity, outage, and customer information in a geospatial format for use by field and operational personnel. Its OMS is fully integrated with interactive voice response and work management related applications among others improving dispatch, outage restoration and work management processes. Its work management system is fully integrated with its engineering analysis, outage management and asset management applications streamlining the trouble ticket and job order creation processes. And, its energy management system is integrated with SCADA and outage management systems for grid operations and monitoring. SMUD is closely followed by LADWP who also has most of the integration among its foundational systems in place. What differs leaders from the followers in this context is the level of integration among the foundational systems. The followers also have some of the same foundational systems deployed. However, these applications are often used as stand-alone applications, and lack the integrations with other applications resulting in manual intensive operations.

Customer Service and Demand Management & Response

The American Recovery and Reinvestment Act (ARRA) grant recipients are leading in the deployment and/or experimentation of sophisticated customer service and demand management & response related Smart Grid initiatives. The ARRA grant recipients' initiatives are summarized below and further detail is provided in Appendix B.

- **APU Smart Grid Project** includes a city-wide deployment of two-way smart meters; an advanced two-way communications infrastructure that leverages public wireless networks available; a meter data management system; time-based rate programs; and advanced customer service options such as programmable communicating thermostats (PCTs) for demand response and customer web portal.
- **BWP Smart Grid Project** includes a city-wide deployment of two-way smart meters; an advanced two-way communications infrastructure that leverages fiber optic backhaul communications network, city-wide wi-fi mesh radio frequency metering communications network and home area networks; a meter data management system; time-based rate programs; and advanced customer service options such as customer web portal, programmable communicating thermostats (PCTs) and in-home displays for demand response; and, energy demand management system.
- **GWP Smart Grid Project** includes system-wide deployment of advanced meters; an advanced two-way communications infrastructure that leverages Ethernet/Internet protocol backhaul and local wireless radio frequency network between meters and utility data systems, and home area networks; time-based rate programs; and, advanced customer service options such as in-home displays and customer Web portal.
- **LADWP Smart Grid Project** includes demonstration of demand response programs and customer behavior. However, apart from the Smart Grid demonstration project LADWP has an extensive ten year investment plan that includes: installation of a hybrid one-way meter reading (AMR) and an advanced two-way AMI metering solution for water and electric customers; evaluation of various residential load aggregation technologies that will provide an option of demand response participation to residential

customers; and, integration of the meter data management system, outage management system, and customer information system with various web services.

- **SMUD Smart Grid Project** includes system-wide deployment of an advanced metering system integrated with meter data management system, existing enterprise and information technology systems, and advanced two-way communications network for smart meters, customer devices, and distribution automation equipment. The project also involves customer systems such as web portals, in-home displays and energy management systems, demand response management systems that enable time-based dynamic rate programs, advanced customer service options, demand response and direct load control programs.

Current State Implementation Assessment

SAIC assessed the level of deployment of enabling Smart Grid technologies and programs related to customer service and demand management and response among the participating POUs. SAIC organized this assessment focusing on the following two areas.

- The level of deployment of enabling technologies for customer service such as advanced metering systems (automated drive- / walk- by meter reading (AMR), advanced two-way metering infrastructure (AMI)), service switches (connect/disconnect), home area network (HAN) enabled meters, in-home displays / monitors, web portal and meter data management system (MDMS).
- The level of deployment of demand response and management related programs/technologies including but not limited to programs to encourage off-peak usage, residential dynamic pricing programs, residential direct load control and demand response systems, commercial and industrial direct load control and demand response systems, residential energy management devices / systems, and more.

Table 9 below presents the level of deployment of the enabling technologies for customer service by the participating POUs as of 2011. The ARRA Grant recipients are in the process of implementing advanced two-way metering systems (AMI) for all their customers, while LADWP is in the process of implementing a hybrid advanced metering system with AMI and one-way drive-/walk- by metering (AMR). Among the ARRA Grant recipients, GWP is leading with full deployment (100 percent) of its AMI system. In addition, the actual deployment of service switches and HANs are currently limited to the ARRA grant recipients. Some of the other utilities are piloting these advanced functionalities. All the ARRA grant recipients are planning to complete their advanced metering deployments within a year or two. SVP is also implementing a two-way metering system for its large commercial customers (7 percent of its customer base) with plans to extend its deployment to all its customers in a phased approach starting in 2012. Among the POUs that currently have a one-way drive-/walk- by metering system, PWP is the only one with 100 percent deployment. And, IID is the only POU which is in the process of conducting an AMI pilot including advanced meters, communication network, service switches, home area networks and meter data management system. Five POUs currently do not have any plans to deploy two-way advanced metering systems in near future.

Table 9: Deployment Level of Enabling SG Technologies for Customer Service by POU

Smart Grid Technologies Advanced Metering	AMP	APU	ALW	BWP	GWP	IID	LADWP	CPAU	PWP	REU	RPU	SMUD	SVP
Drive- / Walk- by Metering System[1]	⊙		◒			●	◒	●	●		●	●	◒
Fixed Network 1-Way Metering System[1]							◒	⊙			◒		
Fixed Network 2-Way Metering System[2]		◒		◒	●	⊙	◒	○				◒	◒
AMI Communication Network[2]		●		●	●	⊙	◒	○	○			●	◒
Service Switches		◒	⊙	◒	◒	⊙	⊙	○				◒	⊙
HAN Enabled meters		◒		◒		⊙	⊙	○				◒	⊙
IHDs / Monitors			○	○	◒			⊙				⊙	
Web Portal	●	●	●	○	●		●	●	●		●	●	●
MDMS[3]		●		●	●	⊙	○	○	○		○	●	◒

○Planning ⊙Piloting ◒Deploying ●Deployed

ALW: Azusa Light & Water
AMP: Alameda Municipal Utility Power
APU: Anaheim Public Utility
BWP: Burbank Water and Power
CPAU: City of Palo Alto Utilities
GWP: Glendale Water and Power
HAN: Home Area Network
IHDs: In-Home Displays
IID: Imperial Irrigation District
LADWP: Los Angeles Water and Power
MDMS: Meter Data Management System
PWP: Pasadena Water and Power
REU: Redding Electric Utility
RPU: Riverside Public Utilities
SMUD: Sacramento Municipal Utility District
SVP: Silicon Valley Power

1- All the POUs who already have or are in the process of deploying one-way drive-/walk- by metering preferred Itron as their AMR vendor.
2- POUs display a great variety in their choice of vendors for two-way AMI metering and communications network:
   a. APU is installing Itron Meters with Tantalus Communication system for its residential customers and SmartSynch system for its commercial and industrial customers.
   b. BWP is installing Trilliant/GE electric meters and collection system for its electric customers and Itron water AMI and collection system for its water customers. These systems will utilize fiber and Tropos Wi-Fi as a backhaul communication network.
   c. GWP has installed Itron OpenWay® power meters and Water SaveSource™ water meters along with Tropos city-wide Wi-Fi backhaul communication network.
   d. SMUD is installing Landis + Gyr meters for all its customers with SSN Utility IQ AMI head-end system.
3- Itron and eMeter are the two preferred vendors observed among the POUs who already have deployed or are in the process of deploying MDMS

Most of the POUs have a customer web portal. However, the functionality of the web portals is often limited to on-line payments and service connect/disconnect requests along with various information on utility services. However, the ARRA grant recipients are planning to further extend the functionalities and/or deploy new customer web portals within a year or so. These portals will mainly empower customers by enabling them to view their consumption and billing information through the website. For those utilities that are planning to implement advanced demand response and direct load control programs, these portals will also allow customers to:

- Learn about new pricing programs and potential savings that can be achieved through these new pricing programs based on customer's historical consumption data.
- Ability to enroll in new pricing programs, demand response and direct load control program.
- Set preferences and settings for participation in demand response and direct load control programs
- View their savings under these programs.

All the ARRA grant recipients, except LADWP have deployed a meter data management system. However, LADWP currently has an in-house database solution for its metering data. SVP is also in the process deploying an MDMS within a year or so. All these utilities will use MDMS as a system of records for meter reading data from their AMI systems. At a minimum, MDMS will be integrated with AMI systems and customer information systems to complete the meter to bill process. In addition, all the utilities have also stated intent to integrate their MDMS with customer web portals and/or outage management systems. LADWP is currently in the process of integrating its metering database, outage management system and customer information system with various web services. LADWP's intent through these integrations is to provide accurate and timely information to its customers regarding their consumption, billing, any pending outages and restoration statuses through its customer portal. The customers will have the option to adjust their accounts to set up their profile and notification preferences using the web services. IID is utilizing a vendor hosted MDMS for its limited number of advanced meters.

Table 10 below presents the level of deployment of demand response and management related programs and technologies by participating POUs as of 2011. SMUD is leading in deployment and/or experimentation of such programs and technologies. Through the ARRA funding, SMUD is piloting to extend its air-conditioning load management program into a dynamic price-enabled direct load control program via the use of programmable communicating thermostats and/or home energy management systems along with other related initiatives. As presented in the table below, the experimentation /deployment of dynamic pricing programs, demand response and/or direct load control programs/technologies are currently limited to the ARRA grant recipients. These utilities are either planning, piloting or in the process of implementing such programs and technologies. However, most of the utilities have stated that they either have or in the process of deploying programs to encourage off-peak usage by their customers to some extent. The remaining few are either piloting or planning to implement such programs in near future.

Table 10: Deployment Level of DR and DM Related Programs & Technologies by POU

DR & DM Programs / Technologies	AMP	APU	ALW	BWP	GWP	IID	LADWP	CPAU	PWP	REU	RPU	SMUD	SVP
Programs to encourage off-peak usage	Planning	Deploying	Deploying	Deploying	Piloting	Deploying	Deployed	Planning	Deploying	Deploying	Deploying	Deployed	Deploying
Residential TOU/Dynamic Pricing Programs		Deploying		Deploying	Planning			Piloting	Deployed			Planning	
C&I Direct Load Control Systems		Deploying		Planning	Deploying		Planning					Deployed	Planning
C&I Demand Response System				Planning	Deploying		Deploying	Piloting				Deployed	Planning
Residential Direct Load Control Systems					Planning		Deployed					Deployed	Planning
Residential Demand Response System				Planning	Planning		Piloting					Piloting	Planning
Residential Energy Management Devices/Systems		Deploying			Deploying		Piloting	Planning				Piloting	Planning
Programmable Controllable Thermostats		Planning		Planning	Planning		Planning	Planning				Piloting	
Interactive HVAC Thermal Storage[2]		Deployed	Deployed	Deploying	Deploying					Deploying			
Smart Appliance Programs[3]		Planning										Planning	

○Planning ⊙Piloting ◒Deploying ●Deployed

ALW: Azusa Light & Water
AMP: Alameda Municipal Utility Power
APU: Anaheim Public Utility
BWP: Burbank Water and Power
C&I: Commercial & Industrial
CPAU: City of Palo Alto Utilities
DR & DM: Demand Response & Demand Management
GWP: Glendale Water and Power
HVAC: Heating, Ventilation and Air- Conditioning
IID: Imperial Irrigation District
LADWP: Los Angeles Water and Power
PWP: Pasadena Water and Power
REU: Redding Electric Utility
RPU: Riverside Public Utilities
SMUD: Sacramento Municipal Utility District
SVP: Silicon Valley Power
TOU: Time-of-Use

1- BWP, GWP, LADWP and SMUD will install demand response / management systems (DRMS) for management and control of customer consumption. BWP will install a demand management system by Open Access Technology International (OATI).
2- APU. ALW, BWP, GWP and REU already have deployed or are executing deployment of interactive HVAC thermal storage units. All these utilities have chosen the Ice Bear units by Ice Energy. When deployed, BWP will have 2 MW thermal energy storage capacity and GWP will have 1.5 MW thermal energy storage capacity.
3- SMUD and APU are the only two utilities intent to enable control of smart appliances through their communication infrastructure.

Grid Automation and Management

Based on the SGMM survey responses, SAIC conducted a preliminary assessment of the level of deployment and experimentation with grid automation and management related technologies and programs among the participating POUs. SAIC focused its grid automation assessment to substation and distribution automation only because most of the participating POUs, except LADWP and SMUD, do not own transmission assets. SAIC identified thirty questions from the SGMM survey's Grid Operations, Work & Asset Management and Technology domain questionnaires. Each of these domains assesses capabilities and characteristics that are directly related with the level of distribution /substation automation, monitoring, control and management capabilities planned for and/or enabled by POUs.

Based on these responses, all the participating POUs are evaluating and/or testing grid monitoring and control technologies such as new sensors, switches and communications to some extent. LADWP and SMUD are again taking the lead by their evaluation and testing of such technologies.

In addition:

- Nine POUs reported that they are either planning to evaluate or are in the process of evaluating potential uses of remote asset monitoring while seven POUs reported that they are either planning to pilot or in the process of piloting with remote asset monitoring of key grid assets to support manual decision making. Eleven POUs also reported that they are either in the process of or have already completed conducting pilots for business unit applications based on connectivity to intelligent electronic devices (IEDs). Out of the seven POUs currently deploying AMI systems and advanced meters with two way communications, six are planning to use smart meters as important grid management sensors within their networks.

- Nine POU's reported that they are either in the process of developing or have already developed an integrated view of geographical information system (GIS) for asset monitoring based upon location, status and interconnectivity. APU and SMUD are in the lead by completing and implementing an integrated view of GIS for asset monitoring for greater than 80 percent of their asset classes. And, six POUs reported that they have a complete view (including location and interrelationships) of their assets based upon status (including security state), connectivity and proximity. APU and SMUD are again taking the lead by having a complete view, respectively 76-100 percent and 51-75 percent, of their assets based upon status, connectivity and proximity. While nine POUs reported that they have implemented condition-based maintenance of key components to some extent, only six POUs reported that they are either in the process of developing or already modeling reliability of grid equipment. However, only two POUs reported that 1-25 percent of their asset models are based upon real (both current and historical) performance and monitoring data.

- Ten POUs reported that they are currently investing in expanded data communications network in support of Smart Grid operations. And, out of these ten POUs, three reported that they have completed investments in data communication serving more than 80 percent of the grid.

- Ten POUs reported that they are either planning to implement or are in the process of implementing distribution to substation automation. Out of this ten POUs, SVP is in the lead in distribution to substation automation with greater than 70 percent implementation and closely followed by APU, REU and SMUD with less than 70 percent implementation.

- Ten POUs reported that they have automated outage detection at their substations. Out of this ten, eight reported that they have 76-100 percent of their substations equipped with automated outage detection. Six POUs reported to have automated outage detection and proactive notification to some degree at circuit level. And, nine reported that they are evaluating outage and distribution management systems linked to substation automation beyond SCADA at least to some extent. Among these POUs, only five are either planning to implement, currently piloting with, or in the process of implementing advanced outage restoration schemes that automatically resolve (self-heal) or reduce the magnitude of unplanned outages. And, only two of those POUs reported that 1-25 percent of their operational grid employs self-healing operations. Among the other POUs, LADWP and REU also reported that respectively 26-50 percent and 1-25 percent of their operational grids employ self-healing operations.

- Ten POUs reported that they are either in the process of developing or already have an advanced sensor plan (such as, for situational awareness, for near real-time control, using phasor measurement units (PMUs) or other sophisticated sensors) within one or more functions and/or lines of business (LOB). And, eight POUs reported that they are either in the process of developing or already have distributed intelligence and analytical capabilities that are enabled through Smart Grid technologies within one or more functions and/or LOB. Among the participating POUs, SMUD is leading by having an advanced sensor plan that supports multiple functions and/or LOB and having distributed intelligence and analytical capabilities integrated across multiple functions and/or LOB. Ten POUs reported that they are either in the process of developing or have sufficient wide-area situational awareness to enable real-time monitoring/control/mitigation in response to complex events (such as, natural disasters, severe weather, extreme demand fluctuations, and so forth.)
- Six POUs reported that grid operations planning transitioned from estimation to fact-based using grid data made available from Smart Grid deployment to some extent. And, seven POUs reported that grid operational management is based on near real-time data to some extent. LADWP is leading the California POUs in these two aspects by conducting 75-90 percent of its planning decisions fact-based and 76 percent-90 percent of its operational decisions using near real-time data. Four POUs reported that they have already implemented smart grid-specific technology to improve cross-LOB performance (such as, peak demand management, fault detection, integrated Volt/VAr Optimization) within one or more functions and/or LOB while four POUs implemented such technologies only as pilots or demonstration projects so far. Five POUs reported that they are either in the process of developing or currently using predictive modeling and/or near real-time simulation to optimize support processes (such as, for maintenance, power management, call center, decision support) to a little extent (1-25 percent).
- Five POUs reported that grid operations information has been made available across functions and LOB and that there is end-to-end observability of grid data to some extent. Among these POUs, AMP and LADWP are the only ones that currently have at least one analytics-based decision that is being automatically executed within protection schemes. BWP, GWP and SMUD are planning to have this capability in the future. LADWP is in

the lead by applying proven analytics-based control and automated decision-making with less than 50 percent system-wide.

Overall, based on the SGMM results, ARRA grant recipients are mostly leading the California POUs with the level of experimentation and/or deployment of DA, asset monitoring, control and management related technologies and programs. The DA and distribution management related Smart Grid initiatives of the ARRA grant recipients are summarized below and further detail is provided in Appendix B.

- **APU Smart Grid Project** involves an expansion of distribution automation capabilities, which include circuit switches, remote fault indicators, and smart relays. The DA devices will be remotely monitored & controlled via SCADA enabling improved outage management, distribution circuit monitoring, and automated circuit switching. In addition to the ARRA funded Smart Grid initiatives, APU envisions a "complete" automation of its distribution circuits with SCADA fiber optic and packet radio communication network expansion, system protection upgrades, substation automation, cyber security improvements, switch automation and capacitor bank automation projects.
- **BWP Smart Grid Project** includes installation of distribution automation communications network, installation of distribution automation devices and technologies including automated reclosers on 106 out of 117 circuits, demonstration of automated feeder switches, capacitor banks, and fault indicators on select circuits to enhance the reliability and quality of electric delivery. The project also includes building a distribution management system which will be utilized in real-time as the analysis engine to monitor system conditions for remote feeder sectionalizing, fault detection and substation/voltage monitoring. In addition to the ARRA funded Smart Grid initiatives, BWP is also undertaking implementation of: mission critical asset protection program; outage management and interactive voice response systems; and, AMI meters for distribution transformer monitoring as part of its distribution automation and management efforts.
- **GWP Smart Grid Project** includes installation of distribution automation systems and communications network that also leverages AMI communications network and energy efficiency improvements. Distribution automation systems include the demonstration of automated feeder switches, feeder monitors, remote fault indicators, and automated capacitor controls on select feeders. These devices are being implemented in conjunction with a distribution management system (DMS), a load management system, and an outage management system (OMS). Distribution system energy efficiency improvements involve the integration of automated capacitor with a power quality monitoring system to improve voltage and volt ampere reactive (VAR) control, power quality, and distribution capacity by reducing energy losses on the distribution system. In addition to the ARRA funded Smart Grid initiatives, GWP is also undertaking implementation of Enterprise Service Bus (ESB), geographical information system (GIS), Asset Management System (AMS), Transformer Information Load Management System

(TILM), Load Forecasting System (LFS), & Mobile Workforce Management System (MWFM)as part of its distribution automation and management efforts.

- **LADWP's Smart Grid Project** includes demonstration of next-generation cyber security technologies to show grid resilience against physical and cyber-attack, an operational testing approach for components & installed systems, and redefine the security perimeter to address Smart Grid technologies. However, apart from the Smart Grid demonstration project LADWP has an extensive ten year investment plan that includes transmission automation, substation automation, distribution automation, communications network expansion, system and data integration and cyber security initiatives. Once these initiatives are completed, the full functionality of LADWP's Smart Grid will include but not limited to outage notifications, transformer monitoring, capacitor and line switch controls, fault management and surge protection among others.

- **SMUD Smart Grid Project** involves a partial deployment of advanced distribution grid assets that equip SMUD's distribution circuits with automated control and operation capabilities. The project includes: deployment of automated switches, automated capacitor banks, remote fault indicators, and feeder monitors integrated with energy management system on 102 distribution circuits; expansion of communication system from automated devices to Distribution Management System; expansion of SCADA system at 36 substations; and, demonstration of the interoperability between distribution management system, outage management system, and advanced metering infrastructure for automated and integrated Volt/VAr control and switching.

Current State Implementation Assessment

SAIC assessed the level of deployment of enabling Smart Grid technologies and programs related to distribution/substation automation and management among the participating POUs. SAIC organized this assessment focusing on the following two areas.

- The level of deployment of distribution operations and management related functions/programs such as, including but not limited to, remote control of protection settings, fault detection and location, smart feeder switching, capacitor management voltage optimization, asset monitoring and distribution system monitoring and measurement.

- The level of deployment of enabling technologies and devices for distribution automation and management such as, including but not limited to, automation devices (automated capacitors, feeder/line switches, voltage regulators; transformer monitors; smart relays, reclosers and sectionalizers; remote fault indicators; sensors; remote terminal units, and so forth.), distribution automation communication network and distribution management systems

Table 11 below presents the level of deployment of distribution operations and management related programs by participating POUs as of 2011. As presented in the below table, most of the California POUs are conducting substation automation programs enabling remote control of protection settings and planning or piloting various distribution automation and management programs for fault detection, automated feeder management and voltage regulation. However, the deployment of advanced distribution operation and management functions such as FLISR, voltage optimization and CVR are mostly limited to ARRA grant recipients with few exceptions.

Table 11: Deployment Level of DA Related Programs by POU

DA / DM Functionality	AMP	APU	ALW	BWP	GWP	IID	LADWP	CPAU	PWP	REU	RPU	SMUD	SVP
Remote Control of Protection Settings		◒		◒	⊙	◒	◒	○	○	◒	◒	◒	
Fault Detection and Location		◒		○	⊙			⊙	◒			◒	
Fault Location, Isolation and Service Restoration (FLISR)		○		○	⊙		○	○				◒	
Automated Feeder Switching		○		○	⊙		○	○	⊙			○	
Feeder Peak Load Management				○	⊙				○			⊙	
Advanced Volt/VAr Control		○		○	⊙	⊙	○		○			⊙	
Real-time Power Flow				○	⊙			○				⊙	◒
Voltage Optimization		○		○	⊙		○		○			⊙	○
Conservation Voltage Reduction		○		○	⊙							⊙	
Remote Asset Monitoring		●		○	○			○	○		◒		○
Predictive/Condition Based Maintenance		○		○	○		○				◒	○	○
Distribution System Monitoring/Measurement for System Assessment and Planning		○		○	⊙		○	○	○	◒	◒	◒	○

○Planning ⊙Piloting ◒Deploying ●Deployed

DA / DM: Distribution Automation / Distribution Management
ALW: Azusa Light & Water
AMP: Alameda Municipal Utility Power
APU: Anaheim Public Utility
BWP: Burbank Water and Power
CPAU: City of Palo Alto Utilities
GWP: Glendale Water and Power
IID: Imperial Irrigation District
FLISR: Fault Location, Isolation and Service Restoration
LADWP: Los Angeles Water and Power
PWP: Pasadena Water and Power
REU: Redding Electric Utility
RPU: Riverside Public Utilities
SMUD: Sacramento Municipal Utility District
SVP: Silicon Valley Power

Table 12 presents the level of deployment of enabling technologies for the above mentioned programs and functionalities. Most of the California POUs are either investing in or planning to invest in expansion of their distribution automation communication networks in support of advanced distribution and substation operations.

Table 12: Deployment Level of DA Related Technologies by POU

Smart Grid Technologies: DM Systems / Technologies	**AMP**	**APU**	**ALW**	**BWP**	**GWP**	**IID**	**LADWP**	**CPAU**	**PWP**	**REU**	**RPU**	**SMUD**	**SVP**
Automated Feeder / Line Switches	○	●		○	◒		○	○	○			◒	
Automated Capacitor Banks		●	●	○	◒		○		○				
Automated Line Voltage Regulators				○			○		○			○	○
Feeder metering by phase (kW, kVAr, Amps) in the substation[1]		●	◒	○	●	●	●	●	●	●	●	◒	●
Downstream feeder metering by phase (kW, kVAr, Amps)[1]			○	○	◒			○				◒	
Communicating Faulted Circuit Indicators	○	●		○	◒		○		◒			◒	○
Distribution Transformer Monitors							○						
Substation Transformer Monitors	○		⊙	○	●			○		○	◒	●	○
Smart relays / IED[2]		●	●	◒	◒			◒		◒	◒	◒	
Fault Current Limiter		●		○	◒								
Phasor Measurement Units							●						
Remote Line Sensors				○	◒			○			●	◒	
Advanced LTC / Regulator Controls				○								●	●
Smart Reclosers				◒	◒				○		◒	◒	
Smart Sectionalizers				○					○			◒	
Smart Distribution Switches	○	◒		◒	◒	◒	◒	○	○				
Smart Fuses													
DA Communication Network	◒	●	○	●	◒		◒	○	○	◒	⊙	◒	●
Distribution Management System (DMS)[3]				○	◒		○					○	

○Planning ⊙Piloting ◒Deploying ●Deployed

DA & DM: Distribution Automation & Distribution Management
DMS: Distribution Management System
ALW: Azusa Light & Water
AMP: Alameda Municipal Utility Power
APU: Anaheim Public Utility
BWP: Burbank Water and Power
CPAU: City of Palo Alto Utilities
GWP: Glendale Water and Power
IID: Imperial Irrigation District
IED: Intelligent Electronic Devices
LTC: Load Tap Changer
LADWP: Los Angeles Water and Power
PWP: Pasadena Water and Power
REU: Redding Electric Utility
RPU: Riverside Public Utilities
SMUD: Sacramento Municipal Utility District
SVP: Silicon Valley Power

1- Most of the California POUs are conducting feeder metering by phase in the substation, however downstream feeder metering is only being deployed by SMUD.
2- Most of the POUs are installing smart relays and IEDs to enable automated protection and control at substations.
3- BWP, GWP, LADWP and SMUD are the only utilities planning to implement distribution management system for advanced integrated management and control of grid operations such as automated fault location isolation and service restoration (FLISR) and voltage optimization.(Volt/VAr control and/or conservation voltage regulation (CVR))

Distributed Energy Resources & Distributed Generation

Based on the SGMM survey responses, SAIC conducted a preliminary assessment of the level of deployment and experimentation with distributed energy resources (DER) and distributed generation (DG) among the participating POUs. SAIC identified nine questions that are directly related with the level of DER/DG deployment and management capabilities planned for and/or enabled by POUs from the SGMM survey's Grid Value Chain Integration and Customer domain questionnaires.

Based on these responses:

- Nine of the participating POUs have a strategy in place for developing, enabling, and managing a diverse resource portfolio (such as, integration of new resources such as demand response, distributed generation), and are already executing to those strategies. Two POUs reported that they are in the process of creating a strategy. Out of these eleven POUs, five POUs reported that they have already identified distributed generation sources and the capabilities needed to support them and two POUs reported that they have already identified energy storage options and the capabilities needed to support them. Out of the thirteen POUs, three POUs reported that they have identified neither the distributed generation sources, energy storage options nor the capabilities needed to support them. The remaining POUs are all either planning to or in the process of identifying their options.
- Four POUs reported that they have already completed environmental proof-of-concept projects (such as, solar or wind generation) to demonstrate Smart Grid benefits to the public and the environment and that the deployment of distributed generation projects are in progress. Five POUs reported that they are currently conducting pilots to support a diverse resource portfolio (such as distributed generation, demand-side management, demand response, storage).
- Four POUs reported that they have at least enabled one new resource (such as, plug-in hybrid vehicles, storage, demand response) to provide substitutes for market products and to support reliability or other objectives. Among these POUs, LADWP is taking the lead with numerous new resources already enabled or deployed. In addition, two POUs reported that they have identified such resources but have not enabled them yet.
- Five POUs reported that they are in the process of redefining the value chain based upon Smart Grid capabilities (including distributed generation, micro-generation, energy storage, and other new customers and suppliers).
- All the participating POUs reported that they have in-home net billing programs available (for example, credit/payment for solar panels, wind, electric vehicle battery to grid) to at least 1-25 percent of their customers. And, six POUs reported that such programs are available to 76-100 percent of their customers. However, only three POUs reported that they have the necessary support infrastructure such as net billing and control in place to support plug-and-play customer-based generation.

California’s POU’s indicate that the following mandated state regulatory goals require the integrating of DER/DG, and the all of the POU’s are to some degree working to meet these goals:.

- **SB1078 & SB 107:** 20 percent of California's electricity come from renewable sources by 2017
- **EO S-14-08 & CARB “RES” Resolution 10-23:** All retail sellers of electricity shall serve 33 percent of their load with renewable energy by 2020
- **AB32 & EO S-3-05:** Meet the greenhouse reduction goal of 1990 levels by 2020 and 80 percent below 1990 levels by 2050
- **California Solar Initiative per SB1:** Established a new customer-owned distributed solar generation goal of 3000 MW of which 700 MW is the collective goal for POUs by 2017.
- **California Clean Energy Future (CCEF) Goal:** 1 million plug-in vehicles in California by 2020.
- **Zero-Net-Energy:** All new residential construction in California will be zero net energy by 2020 and all new commercial construction in California will be zero net energy by 2030.

Overall, based on the SGMM results, ARRA grant recipients are again mostly leading in experimentation and/or deployment of DER/DG resources, and technologies enabling advanced management and control of these resources. The DER/DG integration and management related Smart Grid initiatives of the ARRA grant recipients are summarized below and further detail is provided in Appendix B.

- APU’s ARRA funded Smart Grid project does not include integration of DER/DG resources such as energy storage technologies or plug-in vehicles. However, per APU’s Smart Grid Deployment Plan filed with the Energy Commission, APU is planning to utilize and control locally installed small generators and renewable resources to offset circuit loading at the substations and the grid.
- **BWP Smart Grid Project** includes installation of 15 plug-in electric vehicle charging stations and 280 thermal energy storage units (Ice Bear units) which represent approximately 2 MW of thermal energy with grid operator controlled power inverter technology to provide voltage regulation and control of active and reactive power output.
- **GWP Smart Grid Project** includes installation of plug-in electric vehicle charging stations, Electric Vehicle Management (EVM) system and 214 thermal energy storage units (Ice Bear units), which represent approximately 1.5 MW thermal energy, along with controls to manage peak electric demand.

- **LADWP Smart Grid Project** includes a demonstration of electric vehicle integration into the LADWP grid to demonstrate aspects such as smart charging and battery aggregation; renewables and electric vehicle battery integration; an operational microgrid; and electric vehicle test bed sites at University of Southern California and University of California, Los Angeles. Apart from the Smart Grid demonstration project, LADWP has an extensive ten year investment plan that includes: real-time monitoring and control of renewable sources, which will be equipped with automation equipment to facilitate peak shaving activities and to better support the adoption and utilization of renewable; Feed-In Tariff (FiT) program which gives LADWP customers the opportunity to sell energy to LADWP; and, Solar Photovoltaic Incentive Program which provides financial incentives to LADWP customers who purchase and install their own solar power systems.
- **SMUD Smart Grid Project** includes a field test of up to 220 plug-in electric vehicle charging stations to assess their technical performance, vehicle charging patterns, and effects on electric distribution system operations. The equipment will be operated and further tested under direct load control and dynamic rates using the demand response management system.

Current State Implementation Assessment

In addition, SAIC also assessed the level of deployment of DER/DG resources and the related integration and control technologies among the participating POUs. As presented in Table 13 below, most of the utilities have already integrated renewable distributed generations in to their portfolio both at utility and large customer level. Due to the aforementioned state level regulatory goals, most of the California POUs are also seeing residential roof-top PV installations in their service territories. However these residential installations are not connected to the utilities' grids.

Several POU's are in the process of planning the use of advanced DER control systems and power inverter technologies to integrate and gain further control of these resources in response to demand response and system reliability events. Most of the utilities are also planning or piloting integration of energy storage units into their portfolio. Many of the utilities are either planning or in the process of installing plug-in electric vehicle charging stations in their service territories however, only four of those utilities are planning to deploy electric vehicle control systems to further control and manage the electric vehicle charging loads in response to demand response and/or system reliability events. However, we are not aware of any utilities planning to enable vehicle-to-grid (V-2 G) integration to further use plug-in electric vehicles as an energy source when needed by the utility and/or other operators for grid reliability.

Table 13: Deployment Level of DER/DG Related Technologies by POU

Distributed Energy Resources (DER) / Distributed Generation (DG) Technologies	AMP	APU	ALW	BWP	GWP	IID	LADWP	CPAU	PWP	REU	RPU	SMUD	SVP
Renewable Distributed Generation													
- Residential			⊙	○	○		○	○			○	⊙	○
- Commercial/Industrial		◒	◒	◒	◒	◒	◒				◒	◒	◒
- Utility		◒	◒	◒	◒	◒	◒				◒	◒	○
Fossil Fuel Distributed Generation													
- Residential													
- Commercial/Industrial		●		●	●	●	●		●	●	●	●	●
Energy Storage		○		⊙	◒		○	○	○			⊙	○
Power Inverter Technologies[1]		○		○	○		○				○	○	○
DER Interface Control Systems[1]		○		○	○		○				○	○	○
Plug-in Vehicle Charging Stations	○		⊙	⊙	○		○	⊙	○		○	◒	
V-2 G integration													
EV Control Systems				○	○		○					○	

○Planning ⊙Piloting ◒Deploying ●Deployed

ALW: Azusa Light & Water
AMP: Alameda Municipal Utility Power
APU: Anaheim Public Utility
BWP: Burbank Water and Power
CPAU: City of Palo Alto Utilities
DER: Distributed Energy Resources
DG: Distributed Generation
EV: Electric Vehicle
GWP: Glendale Water and Power
IID: Imperial Irrigation District
LADWP: Los Angeles Water and Power
PWP: Pasadena Water and Power
REU: Redding Electric Utility
RPU: Riverside Public Utilities
SMUD: Sacramento Municipal Utility District
SVP: Silicon Valley Power
V-2 G: Vehicle to Grid

1- Anaheim Public Utilities, Burbank Water and Power, Glendale Water and Power, Los Angeles Department of Water and Power, Riverside Public Utilities, Sacramento Municipal Utility District and Silicon Valley Power are in the process of planning the use of advanced DER control systems and power inverter technologies to integrate and gain further control of distributed energy resources.

CHAPTER 4:
Smart Grid Technology Assessment

This section discusses Smart Grid technologies in several categories. It starts with emphasizing the role and importance of information technology in Smart Grid.

It then identifies the specific technologies that fulfill the Smart Grid roles now, and that will fulfill them in the future. A thorough description of the Smart Grid technologies is provided in Appendix C. The appendix is structured in a tutorial nature. It discusses Smart Grid technologies that are emerging and in-service, some at California POUs. Some in-service technologies are older and, as would be expected, are therefore less capable. But this may not impede progress for those POUs that have them because, historically, vendors have been creative and diligent about leveraging previous products as they deploy new ones.

This section then presents seven use cases to illustrate the roles of these Smart Grid technologies in productive contexts. In the context of this report, use cases are defined as containing the following attributes:

- Identify the high-level description of a specific Smart Grid application from a business process perspective
- Describe the applications that will be enabled (such as, what devices or technologies would be used and what are the interactions between various other Smart Grid applications)
- Identify the primary business and operational requirements
- Identify the POU business processes that would be impacted
- Estimate hardware, software and communications requirements
- Forecast the technology and business challenges that POUs may face during implementation

Use cases are different from business cases in that a business case provides the justification for the project. A business case, at a minimum, identifies the needs for the project, expected benefits and costs, options and the expected return on investment (ROI). In Section 5, SAIC developed a business case framework for the economic evaluation of costs and benefits of Smart Grid applications. SAIC then applied this framework to each use case identified herein to serve as a guideline for the POUs for high-level cost benefit analysis of relevant Smart Grid systems and applications.

A review of current Smart Grid standards follows, highlighting areas that are in active development. The end of this section discusses the gaps between current technologies and standards and those that will be required to realize the most capable 2020 vision, as embodied in the use cases. Finally, we address the efforts required to close those gaps.

Smart Grid and Information Technology

The essential take-away points of this section are:

- The scope and value of Smart Grid benefits are amplified as its integration encompasses more of the utility enterprise.
- Smart Grid requires many forms and levels of integration that go well beyond previous levels of utility integration.
- Successful enterprise-wide Smart Grid integration is much more feasible when supported by an enterprise integration framework.
- Few POUs, if any, have an operational integration framework suitable for effective and efficient Smart Grid development.
- An integration framework is composed of equal parts technology, information, operating practice, and organizational culture.
- Many of the means and methods needed for effective Smart Grid integration are available for use today.
- All of the means and methods needed for effective Smart Grid integration are likely to become available for use between now and 2020.
- The diversity of circumstances and priorities among POUs means that no one Information Technology/Back office strategy will successfully "plug and play" at most POUs.
- The one path applicable to all POUs is to adopt and consistently employ an approach that promotes competent decisions: Define goals, establish strategy, examine alternatives, do a business case for the leading alternatives, and then do what is worth doing and is consistent with the strategy.

Organizational Performance Depends on Information Technology

As with most institutions and businesses, the utility enterprise is an elaborate aggregation of people, technologies, information, resources, practices and services. The aggregation is a living system of systems that is always changing in response to a wide range of external and internal conditions that reflect the past, present, and anticipated future of the utility's environment. Day by day, month by month, and year by year, the utility works to survive and prosper in the midst of its own distinct blend of objectives, perspectives, needs, mandates, capabilities, and constraints.

At any given time, a utility's people and technologies have their respective capabilities and limitations that are, within allowable cost, combined and applied to support the business. Over time, the scope, complexity, and distribution of information and functions tend to grow and shift from people to technologies that can transform the enterprise. Thus, the inevitable and ongoing melding of our energy and information ecosystems is spawning the many parts of what will, we hope, congeal into a truly intelligent electric infrastructure, the Smart Grid.

The new capabilities and benefits realized by each POU will depend a great deal on a Smart Grid that productively employs information and services from, and interactions among, an array of intelligent, communicating entities, including people, at every point in the electric supply chain. Many of the more promising Smart Grid capabilities will require orchestration of information and functions in highly distributed components; meaning that much of the desired smartness of the anticipated Smart Grid cannot happen without successful integration of unprecedented scale and complexity. To achieve this integration, POUs will have to build and operate increasingly large and interconnected information frameworks that are far more functional and secure than those in use today. Done right, POUs and their customers can reasonably look forward to timely emergence of improved means and methods for producing, moving, storing, and using electrical energy.

A POU operates and evolves within its own local ecosystem. Some elements of the local ecosystem are very similar for most utilities: new technologies, federal laws and regulations, global and national economic conditions, and trends like an aging workforce. Other elements of the local ecosystem may differ significantly from one POU to the next. This list is much longer and includes things like size of the POU, customers' attitudes and expectations, geography, weather, demographics, regional and local regulation, local economic conditions, financial performance and resources, staff capabilities and limitations, governance, organization, culture, operating practices, physical plant, information and control assets, energy supply, load profile, utilization of outside resources, quality of service, cost of service, environmental compliance, and so forth. These are just some of the notable factors that will shape a POU's Smart Grid priorities and actions, including those pertaining to information technology/back office provisions.

The Goal

The goal for each POU will be to thoughtfully plan and implement the programs that will foster efficient and orderly Smart Grid development that best serves its particular priorities. This includes the degree to which the convergence of information and operational technologies is accomplished by eliminating traditional technical and organizational barriers between the utility's business information technologies (IT) and the operations technologies that monitor and control the utility's delivery systems.

Smart Grid IT Integration

As a general rule, greater extent and quality of integration by a POU will produce increased range and value of the Smart Grid benefits realized by that POU and its customers. The challenge lies in the fact that the majority of POUs—indeed, the majority of utility’s generally—currently employs a complicated and extensively improvised patchwork of systems and processes that fall into two main categories. The first category comprises the known collection of systems and processes that are adequately recognized and understood by their respective communities of interest. For example, the customer information systems (CIS) supports customer service/billing and supervisory control and data acquisition (SCADA) system supports electric system operations. The second category is made up of an unknown number of obscure, possibly unique, and essentially hidden elements that generally are poorly documented (if at all), poorly protected (if at all), and sometimes disturbingly critical to the utility's business and/or operations. Commonly, the elements of both categories are somehow linked with a largely ad-hoc, disjointed, and poorly understood assemblage of electronic and human interfaces that turn the conglomeration of elements into the utility's own distinct biotechnical system.

This is not meant as a criticism, but rather as a forthright observation of an important problem that is shared by many modern businesses and institutions. The challenging circumstances confronting POUs today simply evolved as good people with good intentions did their best to work with whatever resources, constraints, and information they had at the time. Still, in many cases, perhaps most, this is the POU's starting point for Smart Grid evolution.

Framework for Smart Grid Evolution

To use a relevant cliché, information is the lifeblood of a Smart Grid. Good Things will become possible when the right information is provided in a useful form at the right time and place. For Smart Grid, this is about many sources providing a lot of information, in many forms, to a lot of places at many different times, and, once provided, the information must be properly managed and correctly applied to its intended purpose. Knowing this, it becomes clear that a utility will do well to use a robust enterprise integration framework as its foundation for Smart Grid development.

The role of the enterprise integration framework is to act as the utility's unifying structure of means and methods for creating, moving, managing, and applying useful information. As such, the framework must certainly provide technologies and practices for building and managing interfaces between Smart Grid components – standardization around web technologies, an enterprise service bus (ESB), and service oriented architecture (SOA) for example. That's the part that most readers are likely to first think of when they see the words "integration framework". However, the framework can and should go well beyond the interfaces. Most of the key Smart Grid systems require very similar sets of foundational subsystems and processes for things like cyber security, database management, data storage, data communications, backup and disaster recovery. Other, foundational components are provided by key functional capabilities in enterprise systems including asset management, customer information, service order, and workflow management. With such a framework in place, a utility is in a much better position to successfully orchestrate its Smart Grid development and improve other parts of the utility enterprise well.

Fortunately, many workable means and methods for Smart Grid integration are available today, and those means and methods almost certainly will increase and improve rapidly over the next decade. This is driven by strong demand for ever greater integration of automation and information throughout business and industry. The persistent difficulty for each POU will be to determine and balance its priorities for developing an effective integration framework and its priorities for achieving specific Smart Grid objectives.

Integration Technologies and Practices

An enterprise framework supporting Smart Grid evolution must provide a structure of shared and interoperable technologies for creating, moving, managing, and applying useful information. As such, the framework must certainly provide unified technologies and practices for building and managing interfaces among the technologies within the overall system of systems. An example set of unified technologies and practices suitable for POUs includes:

- A strong network infrastructure
- Standard web technologies
- An enterprise service bus (ESB)
- A common information model (CIM)
- Service oriented architecture (SOA)

These are the parts that are likely to first come to mind when an IT-aware reader thinks of a framework. However, the framework can and should go well beyond the interfaces, as discussed in the following paragraphs.

Very similar sets of essential functions are generally required by system platforms that support Smart Grid applications. Examples of these common functions include:

- Cyber security
- Web services
- Data storage
- Database management
- Backup
- Disaster recovery

A utility can effectively fulfill these common requirements with shared system resources. Components suitable for sharing include the hardware and software for virtually every part of a complete system platform. Host processors, memory, network interfaces, and operating system software can be consolidated and shared via technologies for clustering and virtualization. Data storage can likewise be combined and shared in enterprise-class storage management systems. On top of the core platform components, the utility can add a suite of shared software resources that support cyber security, web applications, and database management. The framework of shared system resources will help the utility achieve higher system availability by substantially unifying—and thus simplifying—the physical, logical, and procedural mechanics needed for redundancy and recovery.

A less apparent category of enterprise framework components is a handful of utility application systems that are critical to Smart Grid evolution. Prominent within this foundational application category are asset management, workflow management, customer information/billing, document management, geographical information systems (GIS), and service order management. Significantly, each of these application systems can benefit from using the shared system resources described above. Also noteworthy, the value that can be derived from these systems is much more likely to be fully realized when they are implemented and managed as enterprise systems that are aligned with the utility's Smart Grid goals.

Completing the enterprise framework are the fundamental practices applied to Smart Grid development and integration. The practices of key interest here pertain to the utility's vision and strategy, enterprise cyber security, process design, change management, stakeholder engagement, business case development/maintenance, and risk management. Not surprisingly, these same practices are fundamentally important to business and governance of all sorts; which helps explain why the practices employed are as critical to a utility's Smart Grid evolution as are the technologies deployed. It is useful here to note the simplifying impact of the aforementioned framework of shared system resources; given the number of common requirements that can be supported with shared resources, such a framework can make it easier for a utility to implement uniform practices for integrating, securing, and managing the combined data and processes of the Smart Grid system of systems.

Approach is Critical

The critical task for each POU will be to develop, adopt, and consistently employ an approach that promotes the competent decisions needed for Smart Grid success. The diversity of POU needs and priorities should and will result in a wide diversity of approach details. At the same time, the objectives of all POU approaches should be essentially the same: define goals, understand requirements, establish strategy, examine alternatives, examine the business case for the leading alternatives, and then do what is worth doing (as shown by the business case) and is consistent with the strategy.

While each POU's approach will necessarily be distinct, the most effective Smart Grid programs will be built around a unified body of coordinated practices that address and engage the full utility enterprise. Fortunately, best practices exist that are applicable to each key area of interest and to each form of enterprise. Nevertheless, implementing and managing a unified body of practices will be a challenge that requires long term commitment and focus.

Smart Grid Specific Technologies

The Smart Grid technologies reviewed in detail in Appendix C are organized Smart Grid in the following categories:

- Advanced Metering Infrastructure (AMI)
- Meter Data Management
- Transmission and Substation
- Distribution

- Customer Enabling / Demand Response Technologies
- Distributed Energy Resources/Distributed Generation Integration
- Electric Vehicles
- Communication Infrastructure
- Workforce Efficiency

The take-aways from each category are summarized below.

Advanced Metering Infrastructure

Two technologies constitute advanced metering infrastructure (AMI): metering and communication. Metering is a utility core competency, and utilities generally find that available automated meters are highly capable relative to their requirements. Most AMI communication technologies are available with meters from more than one meter manufacturer, so that metering requirements can be met with almost any communication method. Therefore, the AMI choice usually is driven by the AMI characteristics and the utility's needs in communication.

The AMI communication technologies to revenue meters are categorized into two core options: wired and wireless. The wireless AMI technology providers have typically chosen either radio frequency (RF) mesh or hub-and-spoke (RF Tower) architectures over either licensed and/or unlicensed frequencies, broadband wireless technologies for their solutions. The existing (3G) cellular data networks are also being used as optional AMI infrastructure. The wired AMI technology providers use either the existing power line infrastructure or an existing broadband network as their communications medium.

Table 14 below provides a number of advantages and disadvantages of various AMI network architectures.

Table 14: Advantages and Disadvantages of AMI Network Architectures

AMI Network Architectures	Advantages	Disadvantages
RF Mesh	• Typically lowest cost • Data Rates from 19 kbps to 250 kbps • Highly redundant architecture – every endpoint will have multiple communication paths/ options • Most regions conducive to mesh networks • Largest number of viable vendors/competitors • Fairly mature in smart metering, early grid and DA functionalities • Flexibility architecture to changing distribution system topography • Easy to deploy and implement in a phased approach • Medium level maintenance costs	• Limited to wireless and fiber backhaul • Medium to high functionality (AMI/DR and some Smart Grid) • Inherent uncertainty associated with system latency and throughput • Lower power devices require closer proximity for successful communication • Higher operating costs than PLC
RF Tower	• Similar cost to RF Mesh depending on terrain • High coverage (high power) • Dedicated link between the endpoint and the hub thus has potential to deliver relatively short and defined latency • Lowest cost to maintain • Mature technology	• Lower data rates, less than 25 kbps • Potential throughput and capacity issues for advanced functionality and crowded hubs • Inherent higher risk of losing connection with endpoints due to having only one communication path • Medium to high functionality (AMI/DR and some Smart Grid) • Major design changes are costly
Powerline Carrier (PLC)	• Lower capital costs if substation communication with adequate bandwidth exists	• Possible inadequate bandwidth to reprogram meters and complete advanced smart gird applications • Special consideration may be needed for urban areas • Higher capital cost than RF mesh
Broadband Powerline(BPL)	• Potential higher communication speeds to 20 Mbps • High Functionality	• Highest cost to deploy • Limited wireless backhaul • Limited number of large scale deployments • Small number of viable players • Still in early stages of grid and distribution functions • Limited ability to change design and approach • Highest cost to maintain • Complex to implement • Some terrain coverage not conducive to BPL

Source: [Smart Grid Market and Technology Assessment, SAIC, June 2010].

Meter Data Management

With the increasing deployment of AMI systems that can provide up-to-the minute interval data from service points, meter data management systems (MDMS) have also evolved within the last 10 years. Initially what started as a meter data storage and management solution that typically import data that are delivered by smart metering systems, then validate, cleanse and process those before making it available for typically billing purposes, has evolved into more of a middleware platform that is able to integrate to existing enterprise applications, translate the vast quantities of raw meter data into systems and help to streamline utility business processes. MDMS used as a metering data aggregation platform can reduce integration complexity between multiple metering and enterprise systems. MDMS can also interface with, including but not limited to, outage management systems, workforce management systems, and asset management and engineering systems. MDMS may provide reporting capabilities for load and demand forecasting, management reports, customer service metrics, and other operations and support the activities.

Today, MDMS is more seen as the backbone of AMI; that without it, some argue that fixed AMI metering systems are no more useful than mobile AMR systems[2]. And that, MDMS makes possible most of the ancillary business benefits offered through frequent data acquisition such as outage management, network planning and operations, customer service applications, demand-side planning, and so forth[3]. Furthermore, as Gartner stated in its recent research for meter data management products; "Renewed interest in energy commodity management, which is spurred by energy security concerns and an interest in demand-response programs, is driving the need for multipurpose metering data repositories that can meet requirements outside of their traditional use in a meter-to-cash (revenue management) process"[4]. Network/asset analysis requires consumption data to improve asset utilization and reliability while the increased focus on customer empowerment requires on-demand access to metering and event data for demand response and operations. And, with the increasing integration of renewable distributed generation, distributed energy resources and plug-in electric vehicles (PEVs), MDMS can also store metering data related to these assets, including load profiles, supply data characteristics and make this information available to other external systems for improved grid operations.

According to Gartner Group's research today the MDMS market is served by a diverse group of vendors including stand-alone energy consumption repository providers as well as; data historian solution providers, customer information systems providers, load research and commodity management solution providers, retail and wholesale operations solution providers, and AMI solution providers.[5]Some of these vendors are often repackaging their offerings and

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[2] Hall, Mark D.,"Why Meter Data Management is The Key to Unlocking AMI Usability"

[3] Ibid Hall, Mark D.

[4] "Magic Quadrant for Meter Data Management Products", Gartner Industry Research Note G00225576, Sumic, Zarko, 20 December 2011, Gartner, Inc.

[5] Ibid Sumic, Zarko

extending it into the MDMS market as well. The research highlights that while this may be viewed as opportunity for utilities, and vendors alike to meet diverse customer needs, it may also be an indication of still immature market with various challenges.[6] Some of the challenges observed by Gartner Group are: [7]

- "Misalignment of the software offering mode and market maturity, such as attempting to offer a COTS[8] MDM solution for a market whose needs are not well–articulated…. Because these immature products usually have yet to achieve an appropriate level of configurability, they require extensive customization efforts during implementation."
- "A lack of well-trained and experienced system integrators that can take over MDM system implementation…."
- "A lack of an adequate number of implementations for reference checking…."
- "Scalability/performance issues arising from data volumes (switching from once-a-month consumption reads to 15-minute interval consumption reads increases data volume almost 3,000 times)…."
- "A lack of commonly agreed-on business rules/practices and data standards…"

In addition to the challenges listed above, based on experience, there often seems to be a disagreement within utility departments as to where certain business functions and/or data should reside.

Transmission and Substation

The leading automation and Smart Grid technology in transmission applications is the phasor measurement unit (PMU), a device that records dynamic voltage and current simultaneously with other PMUs and provides the measurements to a processor that uses them to assess transmission conditions. Applications of these measurements include:

- Validating transmission network models
- Determining network stability margins

[6] Ibid Sumic, Zarko

[7] Ibid Sumic, Zarko

[8] COTS – Commercial-off-the-Shelf

- Based on the above margins, maximizing transmission line load while maintaining stability
- Detecting islanding
- Recording network anomalies and disturbances

Substation technology has advanced at a steady pace for the last three decades. In the early years, SCADA became a standard method of first monitoring, and more recently controlling, resources in substations. SCADA systems included sensors on key substation points and a communication box that sent the sensor values back to a SCADA Master Station at the utility distribution operations center. Next, “Intelligent electronic devices” (IEDs) for substation management became available, and these became coordination points for gathering and handling substation sensor data before communicating them to the utility.

Application of substation automation is still rapidly evolving. The automation functions implemented by substation automation shall include but not limited to:

- Volt/VAR management
- Feeder voltage optimization
- Transformer monitoring
- Transformer load management
- Switch / breaker monitoring and control

Distribution

Smart Grid technologies applicable to distribution can be identified as:

- Distribution Automation Devices / Technologies
    - Remote Sensing Technologies
    - Automatic Reclosers
    - Remotely Operable Distribution Switches
    - Faulted Circuit Indicators
    - Voltage Regulators
- Distribution Management Systems/Applications
    - Supervisory Control and Data Acquisition (SCADA)
    - Distribution Management Systems (DMS)
    - Automated Fault Location, Isolation and Service Restoration (FLISR)
    - “Self Healing” Networks

- Real-Time Load Flow (RTLF) Applications and Analysis
- Capacitor Switching
- Voltage Optimization
- Distributed Resource Optimization

Each of these is discussed in detail in Appendix C to describe how they operate and how they are expected to evolve to constitute a Smart Grid element.

Although there are many advantages of deploying distribution automation devices and technologies such as remote sensors, automatic reclosers, and voltage regulators utilities face several challenges in their broad-scale deployment and integration as listed below:

- **Standards and proprietary protocols:** Proprietary protocols can limit distribution automation device/technology integration to the utility operational and back-office systems and thus reduce the overall benefits. Many such distribution automation devices and technologies today support open communication standards like DNP3, modbus, TCP/IP, RS 232, and IEC 61850. However, if an existing SCADA system uses legacy proprietary standards, there will be additional challenges and work required to interface with these devices and technologies.
- **Inadequate communications infrastructure:** Another important challenge limiting distribution automation device and technology deployments is the need for adequate communication infrastructure to support these devices and other advanced technology requirements. This is a capital-intensive requirement and often difficult to finance. Many POUs are implementing wireless communications infrastructure using Wi-Fi and WiMax technologies that have proved to be cost effective and reliable enough to meet these communication requirements.
- **Cyber security:** Cyber security is an essential component of Smart Grid and an important consideration for distribution automation device and technology deployments, as the integrity and availability of data are critical to the proper operation of both these devices and overall grid operations. Data collected from these devices used for operational decisions pose high security concerns as any mal-formed device data can seriously harm the system. Distribution automation devices working on IP-based systems can have inherent vulnerabilities. Proper security measures are required to minimize the probability of unauthorized access. The North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) cyber security standards are considered to be best practices. Although NERC CIP mainly applies bulk power system security, POU’s adherence to CIP protocols can safeguard critical information infrastructure from being hacked or attacked. The National Institute of Standards and Technology (NIST) has articulated several standards for high-level security requirements to protect the power grid from attacks, malicious code, cascading errors, and other threats.

- **Installation requirements:** Installation requirements across vendor products can vary greatly, including the need for a system outage, cross arm replacements, or other special arrangements on poles and lines. POUs may be averse to system outages or pole/line adjustments for installation of distribution automation devices, and it might be challenging to find enough space on the electric pole to mount data concentrators for these devices. However, new products are emerging with less burdensome installation requirements. Additionally, these devices can be vulnerable to acts of nature such as lightning strikes.

Talking about the distribution management systems and applications, the first system that comes to mind is the SCADA system. SCADA systems of today typically monitor and control power system equipment down to the substations. There are very few SCADA installations beyond the substation fence. However, more and more utilities are looking closely at implementing SCADA beyond the substation as communication costs decrease and capabilities increase. High-speed, high-bandwidth, robust, and secure communication systems are now enabling the integration of remote sensors and other distribution automation equipment into SCADA systems.

Due to the increased focus on the development of the future energy delivery infrastructure, the "intelligent / Smart Grid", the utilities are becoming increasingly interested in solutions that can integrate grid information from various platforms such as SCADA, outage management systems (OMS), Advanced Meter Infrastructure (AMI)/Automatic Meter Reading (AMR) systems and more into a single operations and control application. And, this interest is pushing utilities to consider more advanced distribution management systems (DMS) for the planning, analysis, and operation of distribution system networks. Although, the idea of a DMS is relatively new it has evolved from the monitoring and control of SCADA system technologies that now are over 30 years mature. Common DMS functionality includes:

- Remote monitoring and control of distribution equipment (switches, reclosers, regulators, capacitor banks, dynamic VAR compensators, and faulted circuit indicators)
- Asset health monitoring (transformers in particular, but also circuit breakers and protection and control systems)
- Network modeling and analysis (typically power flow, voltage, and faulted circuit analysis)
- Outage management (including automatic outage notification, fault locating, restoration, and verification)

The most advanced DMS technologies include:

- Dispatch and control of distributed resources (especially solar, emergency back-up generators, onsite customer generation, and in some cases micro wind and battery storage)
- Voltage optimization (optimizing service entrance voltage to improve system efficiency)
- Real time/dynamic equipment rating (especially circuits, substation getaways, and transformers)
- Failure prediction (especially in substation and distribution transformers)
- Fault analysis (especially the identification of momentary outages and high-impedance faults)

The 'leading edge' DMS functionalities include:

- System optimization (especially voltage optimization and DER)
- Active load management (including PCTs, but more interestingly the concept of actively managing customer loads to increase load factor)
- Self-healing network operations
- State estimation

Gartner, Inc., the world's leading information technology research and advisory company, issued its "MarketScope for Outage Management Systems" to address the needs of clients seeking solutions to improve their emergency network restoration process and provide an update of vendor positioning for outage management systems. Gartner's research states that "…the narrowly defined "conventional" OMS is disappearing as a distinct software product category. While the need for software that automates emergency restoration functions still exists, it is increasingly being integrated into ADMS[9] products, which provide more-comprehensive distribution operation functionality and incorporate smart grid technologies…"[10].

Customer Enabling / Demand Response Technologies

The home area network (HAN) may give utilities a powerful platform to establish two-way communications with devices in consumer premises. Utility directions in addressing communication to home devices vary widely. Some utilities focus on implementing demand response programs through thermostats and load control devices. Others are pursuing consumer energy awareness through in-home displays (IHDs) and dynamic pricing programs. HANs range from simple in-home energy displays showing colors only, to more

[9] ADMS – Advanced Distribution Management System

[10] "Market Scope for Outage Management Systems", Industry Research G00213240, Zarko Sumic, Randy Rhodes, 8 June 2011, Gartner, Inc.

comprehensive IHDs showing usage, cost, and time. In-home devices IHDs may communicate with include programmable thermostats, pool pumps, water heaters, electric vehicles (EVs), and small scale distributed generation and storage.

Though millions of in-service smart meters include ZigBee radios to communicate with HANs, very few in-home devices to which they might communicate are in service today. Some utilities and vendors are awaiting more complete standards and communication protocols before full adoption of such technology, as there are over a dozen incompatible protocols available for HANs today. Also while deployed smart meters can be remotely updated with new ZigBee firmware, most in-home devices cannot, causing many utilities to wait until the new profile is proven before contemplating large HAN device deployments.

The market for HAN and home energy management systems (HEMS) is at an early stage of development. The vendors range from utility-centric suppliers targeting a key aspect of the Smart Grid (HAN/DR), to home automation vendors seeking to integrate energy management both into stand-alone systems and into systems oriented towards deployment by broadband service providers. Vendors also include "pure-play" HEMS vendors, home networking equipment providers, and enterprise software vendors. However, HAN market does face a number of challenges, market-oriented and technological, as well as broader economic context.

In the case of smart appliances, currently leading appliance manufacturers are engaged in or planning a limited number of “sandbox” or pilot projects with utilities to test consumer adoption and energy management results. These pilots utilize a range of standards, including ZigBee, U-Snap, and even customized hard-wired connections to the appliance. Until more universal standards are agreed upon and supporting utility programs put into place, appliance manufacturers are hesitant to add cost to their products in a highly cost-competitive market without some degree of certainty that the capabilities will be utilized and provide value to the consumer market.

From the utility perspective, integrating customer side devices as a resource for demand response and system reliability will require the ability to better coordinate the communication of demand-response events, monitoring, measurement and verification functions. In addition, with further evolution of Smart Grid it will also require more advanced capabilities, such as predictive analysis and forecasting. Such analysis of the expected participation levels by customers or of the capacity available for each demand response program may be driven by utility’s need to support distribution operations for a planned outage, or to manage the peak load expected on the basis of an extreme weather forecast, or even to support the utility’s ability to bid demand-response as a resource in wholesale markets for capacity, energy and ancillary services. Typically such advanced capabilities will require implementation of demand response and management systems (DRMS), as observed among some of the California POU’s Smart Grid initiatives. Furthermore, it will also require a more integrated approach and platform for resource planning and optimization including demand response, distributed generation and energy resources along with conventional resources in real-time.

Distributed Energy Resources/Distributed Generation Integration

The distributed generation and energy resources (DER/DG) can include programs allowing homes, farms and businesses to generate their own power from renewable sources such as wind, water, solar power, agricultural biomass and utility or customer side storage systems that can send excess electricity back to the grid, and with the mass adoption of plug-in electric vehicles (PEVs) in the future, it can also include the PEVs that can act as distributed generation resources during peak periods. While small amounts of distributed generation will not have a major impact on the distribution grid, widespread concentration of such generation and energy resources, especially with intermittent power flow characteristics (such as wind, photovoltaic, and so forth.), can have very diverse impact on the grid; threaten the reliability of the grid and even the safety and well-being of utility customers and personnel.

These diverse distributed generation resources typically use inverter-based technologies to convert direct current to alternating current that can be at any required voltage level and frequency. However even then, large concentrations of such resources sending electricity back to grid in an intermittent nature can result in a variety of problems around power quality, including over-voltage, under-voltage, phase voltage imbalance, sudden voltage changes, excessive harmonics, frequency fluctuations and unintended-islanding. While sound electricity network design can reduce or eliminate most of these issues, the utility will still have to maintain the real-time visibility of distributed generation sources on the grid, while also monitoring the distribution network constantly for voltage, power-quality, frequency and other instrumentation.

Thus the specific areas that must be addressed with respect to DER/DG integration include: control and dispatch strategies for DER; strategies to ensure the safety, reliability and protection of the grid; and, the role of power electronic interfaces in connecting DER to the grid.

Today, Smart Grid energy management systems are available that collect and analyze real-time load and weather data to provide hour-ahead load and renewable supply output projections, as well as the cost of other available generation resources, so that utilities can perform economic dispatch and minimize generation costs while meeting demand requirements. However, if available, these systems currently do not take into account the customer owned generation and energy resources. Besides, assessing grid reliability impacts requires more of a systems approach supplemented by enabling technologies and platforms to measure, monitor, manage and control the generation resources, the consumption, the grid operations and assets in an integrated manner. Such approach will require implementation of many of the Smart Grid enabling technologies and systems discussed in this Chapter, including but not limited to: advanced metering infrastructures (AMI); two-way communication infrastructures; distribution and substation automation devices, technologies and systems; and, more.

Another concept often talked about with the increasing integration of DER/DG is the microgrid. Microgrid is an interconnected network of DER/DG and loads that normally operate connected to a centralized grid but can also function separately (in isolation) from the electricity grid[11].

[11] http://en.wikipedia.org/wiki/Distributed_generation#Microgrid

Many public or private initiatives are underway to investigate optimal microgrid design, including the power electronics necessary to connect microgrids effectively to the power grid; conducting field tests of microgrid operation; and assessing the system reliability services that microgrids might provide.

Electric Vehicles

The technology for large scale use of plug-in electric vehicles (PEVs) is in its infancy. Standards efforts are still under way to define standardized interfaces for the physical charging apparatus and the information transfer between the PEV and the serving utility.

According to a recent analysis forecast by Pike Research global investments in the applications and hardware to enable smart EV charging will grow from $168.7 million in 2011 to $454.8 million in 2015[12]. And, according to the same research:

> "Within the next several years, EV penetration will increase within utility service territories to the point that they exacerbate or extend peak demand and in some regions possibly put grid reliability at risk. Utilities will embrace managing EVs as significant loads that can be shifted as part of DR programs."

Advanced metering infrastructures with two-way communication networks will become vital for utility control and load monitoring for PEV applications. Use of PEVs as a dispatchable resource is still a long way to go, but some utilities are looking at using them as a demand response resource through experimentation of rate structures encouraging customers for off-peak charging and the implementation of vehicle management systems to better and monitor and control PEV loads and storage capabilities.

In addition, other central PEV issues still remain unresolved, including how long it takes to recharge them, how to pay for electric delivery infrastructure needed to charge them, and how their materials will be recycled at end-of-life.

Communication Infrastructure

From communications infrastructure perspective, the Smart Grid can be viewed as the merger of two networks: the electrical transmission & distribution (power) network, and the modern data communications network. While this concept is not new, the integration of more: less deterministic resources such as renewable power generation and electric vehicles; and, dynamic demand that is more responsive to price and supply elasticity through customer empowerment and participation in demand response into the grid, requires the creation of an automated, distributed, and secure control system of immense scale, with reliable, flexible, and cost-effective communications networking as the fundamental enabling technology.

Typical Smart Grid communications architecture consists of four layers; enterprise network, wide-area network (WAN), local-/neighborhood- area network (L/NAN) and home-area network (HAN). Or, from applications perspective communication infrastructures can be

[12] "Smart Grid: Ten Trends to Watch in 2011 and Beyond", Pike Research, published 4th quarter 2010.

categorized as enterprise, substation automation, distribution automation, advanced metering and home area networking.

The WAN provides the robust, high-capacity and low-latency communication required to fully implement a Smart Grid and is often provided by fiber or a broadband wireless technology (WiMAX, for example) or a combination of both. The L/NAN is often provided by the AMI communications infrastructure and the HANs that are being deployed today are mostly wireless - but power line communication options are also emerging. The ZigBee Alliance and the HomePlug Powerline Alliance are collaborating to provide a multiple-medium solution for HANs where no single medium can provide adequate reliability.

The Smart Grid utilizes a broad mix of public and private, wired and wireless, licensed and unlicensed, and standard and proprietary communications technologies. Thus, private fiber, point-to-point microwave, and satellite for substation and/or field applications (such as vehicle tracking, workforce management, and so forth.) connectivity, with 3G cellular and unlicensed private RF mesh nodes can all be observed in the communication network of a single utility. On the other hand, regulatory forces, coupled with government funding, is driving unparalleled standards development efforts and cooperation among many stakeholders, challenging today's proprietary systems with internet-inspired network equipment. These efforts are expected to drive even more change in the utility applications of communication infrastructures similar to the evolution of enterprise and telecommunications networks seen over the last 20 or 30 years into a single, integrated voice/video/data network.

Although National Institute of Standards and Technology (NIST) has created a framework for evaluating and recommending specific standards for use in the Smart Grid there is still more to be done. The NIST effectively identified the gaps where appropriate standards do not yet exist and has organized the industry to address these gaps. But, as also stated in the PikeResearch's research report[13], there are still significant risks inherent in the evolution of Smart Grid communications as follows:

> "For example, the highly regulated nature of the electric utility business makes it susceptible to policy and political influence at both the local (for example, consumer acceptance) and geopolitical (for example, energy price shock) levels. In addition, the technical complexities associated with widespread renewable distributed energy generation (RDEG) and plug-in hybrid electric vehicles (PHEVs) are not yet fully understood. Finally, the security concerns associated with a distributed control system on the scale of a fully interconnected continental Smart Grid are not fully appreciated by either policy makers or technologists. As such, building, securing, evolving, and managing the communications network portion of the Smart Grid represents one of the great challenges and opportunities of today."

[13] Gohn, Bob, Wheelock, Clint, "Smart Grid Networking and Communications: WAN, NAN, and HAN Communications for Substation Automation, Distribution Automation, Smart Meters, and the Smart Energy Home", Research Report, Pike Research, published 3rd Quarter 2010.

Workforce Efficiency

Among other things, workforce efficiency can be accomplished with software solutions that give call center operators, field force managers, and dispatch teams computer resources for receiving requests, organizing the utility's responses, tracking the work as it progresses, and analyzing work performance. Mobile workforce management adds data communications, so that field staff can retrieve current information and receive updated instructions and assignments at any time. Technological advancements and declining hardware, software, and wireless service costs are making mobile workforce solutions more reachable to every utility regardless of its size.

Some of the emerging trends that are likely to drive the implementation of mobile computing solutions in the utility environment going forward are:

- **Changing utility workforce:** As Baby Boomers retire, a younger generation of workers is coming into organizations, bringing with them different life experiences and different expectations. Per the APPA study[14], the GenX generation (born between 1964 and 1981) and the Millennials (born after 1982) frequently lack the knowledge of senior workers, but are technically savvier and expect to use technology to perform their job functions. Utilities failing to provide enabling technology tools are more likely to find it more difficult to recruit and retain new generation workers and may see their operational efficiencies fall. In addition, the same technology tools, if implemented, can act as a repository to ensure that knowledge from senior workers is not lost, but instead is stored and made available to the entire field workforce.
- **Evolution from Client/Server-Based to Web-Based Applications[15]:** More and more utilities are providing access to corporate applications including mobile workforce computing systems through the use of web-based services/architectures which are often viewed as more easily supportable architectures by utility information technology departments. Mobile workforce solutions with web-based services/architectures provide an easier and more efficient platform for performing upgrades on the mobile devices that are being used by the utility's field crews. Upgrades can be done remotely using wireless technology over the network. Utilities that already have robust mobile workforce computing solutions built on client/server architecture aren't likely to migrate to web-based systems, but the web-based option may appeal to utilities implementing their first mobile workforce computing solutions or to utilities replacing an older mainframe or client/server system that has been left unsupported.

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[14] American Public Power Association, "Work Force Planning for Public Power Utilities: Ensuring Resources to Meet Projected Needs", 2005

[15] The main difference between the client/server-based applications and web-based applications is system access. Client/server-based applications are accessible through the local network or through a remote access application such as Citrix. The remote access applications require additional user software and can increase IT overhead costs. The web-based applications are accessed from anywhere with a standard browser and an Internet connection. The user does not even have to be using his or her, own computer. The cornerstone of web-based applications is Internet connection.

- **Expanded Choices in Mobile Hardware:** Web-based and thin client architectures are driving introduction of even smaller, lighter-weight, less expensive, sub-notebook computing devices such as PDAs, handheld computers, tablets, and netbooks out into the field. Ruggedized and semi-ruggedized laptops will continue to be a better choice for those highly skilled mobile workers that are conducting technical work. With a larger screen and keyboard than handheld computers, laptops have a proven track record in the field. These laptops are especially useful for performing certain tasks where there is a fair amount of information to be presented to the mobile workers and a fair amount of information to be collected at the site.
- **Decreasing Technology Costs:** The utility IT industry has observed huge increases in hardware and software functionality at reduced costs within the last 10 years. Many technologies such as mobile workforce solutions that were initially developed for large utilities are now available for all sizes of utilities due to the continuing trend in the decreasing cost of the mobile workforce computing solutions, from mobile computing devices to the workforce management solutions and the wireless network that interconnects them. The emergence of smaller and "thinner" computing devices drove the cost of field hardware to decline as well. The increasing number of solution providers and utilities that adopted MultiSpeak and other integration architectures such as service oriented architectures (SOA) and web-services also observed large reductions in the cost of system integrations, implementations, and maintenance.
- **Mobile Virtual Private Network (VPN) Solutions[16]:** Due to the trends in core mobile workforce computing systems built on web-based and thin client architectures with thin, ultra-light mobile devices, deploying solutions that stand up to the most demanding communication and connectivity challenges are becoming more imperative. In the mobile environments where bandwidth is limited, connections are unstable, roaming is common, and security is essential, third-generation mobile VPN solutions offer undeniable value. Use of mobile VPN solutions is becoming more and more common in the utility environment due to the communications challenges often observed by utilities serving in expansive service territories with remote locations.

Some of the applications of mobile workforce management / computing solutions include, but not limited to,:

- Automated Design and Staking

[16] Mobile VPN solutions offer all the functionality of the traditional VPNs maintaining an authenticated, encrypted tunnel for securely passing data traffic over public networks (typically, the Internet). Furthermore, mobile VPN solutions maintain a virtual connection to the applications at all times as the endpoints change, handling the necessary network logins in a manner transparent to the user. They enable true mobility to the ultimate mobile worker by keeping application sessions open at all times, connecting via various wireless networks, filling-in connectivity gaps, resuming network communication without disrupting the VPN tunnel even when the devices are in stand-by, "sleep" mode to preserve battery life, and doing all this and more while ensuring seamless security.

- Automated Field Force Tracking
- Automated Outage Ticketing
- Automated Service Ticketing
- Mobile Damage Assessment & Distribution System Inspection
- Mobile Maintenance
- Mobile Asset and Inventory Management
- Automated Meter Services
- Automated Right-of-Way (ROW) Maintenance

Use Cases

The seven use cases summarized below illustrate ways in which Smart Grid is widely expected to benefit utilities and energy users in California and elsewhere in the year 2020. Use cases serve as a reference against which present and future technology capabilities are compared to define the gap between now and the possible capabilities of 2020.

1. **Substation Automation - Integrated Protection and Control Improves Service Reliability**

   The settings for microprocessor-based relays, recloser controls, and protective elements down the line are normally changed only occasionally, and only after engineering analysis to determine proper protective coordination. However, in an advanced Smart Grid implementation, these settings can be dynamically programmed and controlled separately and in coordination, increasing system reliability and stability. This can best be accomplished using the state estimator and real time load flow applications of a Distribution Management System (DMS) to control distribution parameters and microprocessor-based relays, reclosers, and other protective elements to minimize outages and damage to critical distribution assets.

2. **Advanced Metering – Smart Meters Enhance Utility-Customer Interaction**

   Customer load interaction with the grid provides opportunities for the customer to both manage their energy consumption and contribute to grid reliability and efficiency. Advanced metering systems empower customers by providing more visibility to their energy on a near real-time basis. Customers can manage loads to reduce energy and demand charges, for example, scheduling loads to run "off peak".

   Advanced metering infrastructure (AMI) networks not only provide the platform for enhanced customer service options such as remote service switching and pre-pay service but also play a critical role in utility's outage management process by providing real-time outage notification data from the customer/metering locations. It can further enhance the utility's engineering, system operations, management and planning processes

3. **Distributed Energy Resources - Integrated Distributed Generation & Storage Support Grid**

   Diverse energy sources are located throughout the distribution system, including small wind and rooftop solar systems, the energy output of which is highly variable. Energy storage devices connected throughout the distribution system include flywheels, batteries, and thermal devices. In addition, the utility may have a direct load control program controlling such customer loads as air conditioning, pool pumps, and water heaters.

   When the output of the distributed supplies drops in response to short term (for example, less than 5 minutes) changes in wind and cloud conditions, the storage systems sustain the electric system for short periods while the utility manages bulk supply to serve system load on a longer (for example 15 minutes and longer) time scale. The utility's direct load control also contributes by shedding load for periods up to a few hours, as needed, to balance load and supply.

4. **Demand Response – Active Load Management Reduces Peak Demand**

   Customers actively manage their energy consumption in response to information about their energy usage, rate and market (events) information. Customer devices can either autonomously respond to rate/event information initiated by the utility or can be directly controlled by the utility. More complex dynamic rate structures can be established requiring customer devices to be equipped with automated systems that can autonomously react to utility price signals to fully capture the customer driven load response.

5. **Distribution Automation –Integrated Voltage and Feeder Management Improves Power Quality and Delivery Efficiency and Customer Service Reliability**

   The Automated Feeder Management system dynamically collects data from distribution feeders and, when a fault occurs, automatically isolates the fault and restores electric service by switching un-faulted line segments to adjacent feeders with free capacity. The unique element of this concept is the real-time identification and transfer of available capacity from adjacent feeders. This is capacity that normally is not utilized with conventional (manual) load transfer schemes.

   Volt-VAR Control (VVC) controls capacitor banks, load tap changers, and voltage regulators to regulate distribution voltage and minimize reactive power (VAR) flows through distribution lines. Voltage control and VAR control can be operated independently, but optimal benefits are achieved when they are integrated. VVC solutions generally incorporate a centralized voltage optimization algorithm referred as "Conservation Voltage Regulation (CVR)"whose objective is to either reduce peak load, or minimize system losses by reducing energy consumption.

Near-real-time current and voltage data are acquired via supervisory control and data acquisition (SCADA) system, advanced metering infrastructure (AMI) system, or other remote sensors. A state estimator and load flow analysis programs of a distribution management system (DMS) determine the voltage profile for each circuit, and switch capacitor banks and/or feeder sections to optimize the circuits. Once the voltage profile is optimized, substation regulators reduce the feeder voltage to near the practical minimum, reducing losses and saving energy.

6. **Electric Vehicle Charging - Grid Monitoring and Control Enables Wide-scale Electric Vehicle Charging**

   When connected for charging, a plug-in electric vehicle (PEV) links with the utility via the home area network (HAN), the meter, and the AMI network. The PEV displays and the in-home display (IHD) show the customer the battery status and energy cost information, and the customer chooses a charging schedule and fee that meet the customer's needs. The PEV battery is charged and the energy transferred during charging is measured by the utility and provided to the vehicle and the customer.

   If the customer chooses to participate in utility demand response and/or emergency load shed, the PEV may be restricted from charging until an emergency event concludes. The PEV may even discharge to give the grid power for a time. The PEV returns to the user prescribed charging scenario after a discharging event is complete or expired.

7. **Asset Management - Asset Monitoring Enables Proactive System Planning & Maintenance**

   System assessment and planning require distribution load modeling, energy loss calculations, outage tracking and avoidance, and protective system analysis using digital fault data. Smart Grid enables more complete data acquisition and more accurate planning. Engineers can better predict load growth by applying data collected through distribution monitoring systems to a complete network model. System losses may be reduced by identifying load imbalances and redistributing load. Logged data identify feeders with excessive reactive power (VAR) flow as candidates for capacitor bank installations, reducing losses and extending equipment life. Correct operation of protective devices is verified by digital fault data acquired from microprocessor-based relays and recloser controls. Preventative maintenance may be driven by historical recloser and breaker operation trends, instead of by static timelines.

The above use cases are examples of a far broader array of possible Smart Grid operations and benefits that is expected to emerge in the future. No one can predict with clarity all the ways society will leverage Smart Grid technologies. (As just one example, cellular phones that capture and send pictures are now widely used by consumers and workers alike. When cellular telephony was introduced, no one predicted that successor cell phones would function as communicating cameras that would become essential tools to many field workers.) Many other use cases are possible. Though other applications may eventually produce higher value than these examples, these use cases are particularly relevant because they embody the future value that we can recognize now, and that value is the motivation to pursue Smart Grid. The Use Cases are presented in detail in Appendix D.

Smart Grid Standards

In the absence of standards, there is a risk that the increasingly diverse Smart Grid technologies that are being deployed today will become prematurely obsolete or implemented without adequate security measures. The lack of standards may further hamper future innovation efforts and the realization of promising applications, such as price and demand response responsive smart appliances.

In June 2011, the White House released a new report entitled "A Policy Framework for the 21st Century Grid: Enabling Our Secure Energy Future" [17] by the National Science and Technology Council (NSTC). This report requested the National Institute for Standards and Technology (NIST) and the Federal Energy Regulatory Commission (FERC) to continue to facilitate the development and adoption of open standards to ensure that the following benefits are realized:

- Today's investments in the Smart Grid remain valuable and compatible with advancing technology in the future and that the standards can ensure that the devices are installed with proper consideration of the necessary security to enable and protect the grid of tomorrow;
- Shared standards and protocols help reduce investment uncertainty by ensuring that new technologies can be used throughout the grid, lowering transaction costs and increasing compatibility;
- Consumer choice supported by Smart Grid interoperability standards and open standards can reduce concerns on consumer lock-in effect. Using proprietary technologies can make consumer products incompatible with other suppliers' products or services;
- Standards can reduce market fragmentation and help create economies of scale, providing consumers greater choice and lower costs;
- Standards can provide guidance to utilities as they face with new and difficult challenges in cyber security, interoperability, and privacy concerns; and
- Development of international Smart Grid interoperability standards can create export opportunities for U.S. companies, help to open global markets, and achieve greater economies of scale and vendor competition that will result in lower costs for utilities and ultimately consumers.

The following subsections will touch on the areas listed below based on the framework and roadmap for Smart Grid interoperability standards developed by NIST:

[17] http://www.whitehouse.gov/sites/default/files/microsites/ostp/nstc-smart-grid-june2011.pdf.

- Progress to Date
- Future Standards Development
- Suggested Approaches for POUs

Progress to Date

In October 2011, NIST released the second draft version of its framework and roadmap for Smart Grid interoperability standards[18] for public comment. The updated and expanded version adds about 21 new standards, specifications and guidelines to the 75 that NIST recommended in its first roadmap. The new version includes:

- An expanded view of Smart Grid by the Smart Grid Interoperability Panel's (SGIP's) Smart Grid Architecture Committee (SGAC);
- Several developments for ensuring Smart Grid cyber security, which include a Risk Management Framework;
- A new framework for testing and conformity of systems and devices connected to the Smart Grid to enable vendors and other Smart Grid stakeholders to certify the interoperability of devices being considered for a specific Smart Grid deployment;
- More on efforts to coordinate U.S. standards development with standards initiatives internationally; and
- An overview of areas to work on in the future and improvements in the standards process.

The SGIP currently has two committees (the Smart Grid Architecture Committee (SGAC), and the Smart Grid Testing and Certification Committee (SGTCC)), and one permanent working group (Cyber security Working Group (CSWG)) established. The SGAC is responsible for creating and refining a Smart Grid conceptual reference model which includes the identification of the lists of the standards and profiles necessary to implement the vision of the Smart Grid. The SGTCC is responsible for creating and maintaining the necessary documentation and organizational framework for compliance, interoperability, and cyber security testing and certification for Smart Grid standards recommended by SGIP. The CSWG is responsible for assessing the SGIP-identified standards within a risk assessment framework that focuses on cyber security and developing a set of recommended security requirements among other responsibilities. Within CSWG, currently there are about eight subgroups established that address security related concerns in various areas including: AMI security, architecture, design principles, high-level requirements, privacy, research and development, standards, and testing and certification.

[18] Draft NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 2.0, October 17 2011, See:

The SGIP also formed a number of ad hoc working groups, known as Domain Expert Working Groups (DEWGs) and Priority Action Plans (PAPs).[19] Since the installment of the NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 1.0, three additional DEWGs are established: Terminology (TERM), Electromagnetic Interoperability Issues (EMII) and Internet Protocol Standards (IPS), in addition to the six DEWGs identified previously[20]. The TERM DEWG is responsible for establishing a common process and approach around current and developing terms and definitions in use within each of the SGIP working groups. The EMII DEWG is responsible for investigating strategies for enhancing the immunity of Smart Grid devices and systems to the detrimental effects of natural and man-made electromagnetic interference. This group will identify issues and develop recommendations for the application of standards and testing criteria to ensure electromagnetic compatibility (EMC) for the Smart Grid. And, the IPS DEWG will consider functionality related to the use of the Internet Protocol Suite in the Smart Grid.

Since the first release of the Smart Grid interoperability standards in January 2010, deliverables have been produced in the areas of Smart Grid architecture, cyber security, and testing and certification which are summarized below.

An expanded view of Smart Grid architecture includes architectural goals, conceptual reference models for Smart Grid domains and information networks, Smart Grid interface to the customer domain and conceptual business services. The fundamental goals of architectures for Smart Grid have been expanded to include:[21]

- Support for a broad range of technology options for both legacy and new;
- Interoperability;
- Maintainability;
- Upgradeability;
- Innovation;
- Scalability;
- Support for legacy system integration and migration;
- Security;
- Flexibility;
- Governance to promote a well-managed "system of systems"; and

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[19] http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/SGIPWorkingGroupsAndCommittees.

[20] Previous DEWGs include: Transmission and Distribution (T&D), Home-to-Grid (H2G), Building-to-Grid (B2G), Industry-to-Grid (I2G), Vehicle-to-Grid (V2G), and Business and Policy (BnP).

[21] The list is expanded and revised from the goals described in Framework 1.0, Section 2.3.1

- Affordability.

To date, SGAC formed teams to review about nine standards and developed detailed reports that contain analyses and recommendations for improvements in these standards. Some of the standards reviewed by SGAC include the following:

- ANSI C12.19: American National Standard For Utility Industry End Device Data Tables; ANSI C12.21: American National Standard Protocol Specification for Telephone Modem Communication;
- IETF RFC 6272: Internet Protocols for the Smart Grid;
- National Electrical Manufacturers Association (NEMA) Upgradeability Standard (NEMA SG AMI 1-2009);
- SAE J2847/1: Communication between Plug-in Vehicles and the Utility Grid;
- SAE J2836/1: Use Cases for Communication between Plug-in Vehicles and the Utility Grid; and
- NISTIR Interagency Report (NISTIR) 7761: Guidelines for Assessing Wireless Standards for Smart Grid Applications.

To further improve the standards evaluation process, the SGAC is developing a standards review checklist. [22]

The SGAC Heterogeneity Working Party is formed to develop evaluation criteria and guidance for the integration of legacy systems to address that:

- New systems should be designed so that present or legacy aspects do not unnecessarily limit future system evolution;
- A reasonable time frame for adaptation and migration of legacy systems must be planned to ensure legacy investments are not prematurely stranded; and
- Legacy systems should be integrated in a way that ensures that security and other essential performance and functional requirements are met.

The ongoing work of the SGAC Heterogeneity Working Party is available on its collaborative Web page[23].

Currently, various Smart Grid functions are supported by independent and, often, dedicated networks such as Internet Protocol (IP) -based network for enterprise data and business networks, and specialized protocols for supervisory control and data acquisition (SCADA)

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[22] http://collaborate.nist.gov/twiki-sggrid/pub/SmartGrid/SGIPDocumentsAndReferencesSGAC/SGAC_PAP_Closeout_Check_list_0v1.doc.

[23] http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/SGIPHeterogeneitySGAC.

systems. However, to fully realize the Smart Grid goals, information must be transmitted reliably over networks and must be interpreted consistently by various applications which require the transmitted information to be well-defined and understood by all involved parties in the process. To promote coordination and consistency of relevant information models within and across the Smart Grid domains[24], the SGAC Semantic Working Party was established. The planned deliverables of this group include the following and will be posted to its collaborative Web page[25] as they are produced:

- Definitions of semantic concepts and methodologies for Smart Grid;
- Semantic harmonization scenarios for use by Smart Grid standards development groups.
- These scenarios will spell out how the framework can be used to integrate (in the general sense) two or more standards;
- Requirements to guide standards development organizations in the development and coordination of canonical data models (CDMs);
- A "map" showing the overall relationships among domain industry standard CDMs, and showing which standard exchanges belong to which domains;

In addition, SGAC Conceptual Architecture Development Working Party has been established to create a set of conceptual business services for Smart Grid. The group will analyze U.S. legislations and regulations pertaining to improving the grid; relate high-level goals identified in these legislations and regulations into lower business-level goals; review use cases and requirements developed by the Smart Grid community; and develop a set of conceptual services that support these requirements. The ongoing work and the outcomes of this group will be available on its collaborative web page[26].

As part of its objectives, the SGIP produces and maintains a Catalog of Standards (CoS). After the publication of the NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 1.0, SGIP established a process for adopting and adding standards to the SGIP CoS. New candidate standards will be identified through the ongoing efforts of the SGIP and its working groups. And, NIST will consider adding those standards to the identified standards list as standards are reviewed and added to the CoS. The SGIP has already incorporated the cyber security and architectural reviews into the standard-assessment and Priority Action Plan (PAP)-activity-assessment processes and moving forward, standard conformance and interoperability testing results will also provide feedback to the standard identification process.

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[24] Smart Grid Domains include Customer, Markets, Service Provider, Operations, Bulk Generation, Transmission and Distribution as defined by NIST.

[25] http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/SGIPSemanticModelSGAC.

[26] http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/SGIPConceptualArchitectureDevelopmentSGAC.

All the existing and new standards are required to undergo a thorough architecture review. The standards identified and those emerging from PAP activities are undergoing architectural reviews conducted by the SGAC.

In July 2011, FERC issued an order[27] stating that there was insufficient consensus for it to institute a rulemaking at that time to adopt the initial five families of standards identified by NIST as ready for consideration by regulators.[28] In that July 2011 order, however, FERC expressed support for the NIST interoperability framework process, including the work done by the SGIP, for development of Smart Grid interoperability standards.

In the cyber security area, CSWG released the first draft of NISTIR 7628, Guidelines for Smart Grid Cyber Security publication in September 2009, the second draft in February 2010, and the first version of the NISTIR 7628 v1.0[29] in August 2010. The NISTIR 7628 publication requires that all existing and new standards identified as supporting Smart Grid interoperability are to undergo a thorough cyber security review as part of the current and future standard identification process. So far, the CSWG has reviewed over 20 standards which can be found at the group's collaborative Web page,[30] and produced detailed reports that provide recommendations for improvements. Some of the standards reviewed by CSWG include:

- Various American National Standards Institute (ANSI) C12 series standards with respect to metering such as:
    - ANSI C12.1: American National Standard for Electric Meters Code for Electricity Metering;
    - ANSI C12.18: American National Standard Protocol Specification for ANSI Type 2 Optical Port;
    - ANSI C12.19: American National Standard For Utility Industry End Device Data Tables;
    - ANSI C12.21: American National Standard Protocol Specification for Telephone Modem Communication; and
    - ANSI C12.22: American National Standard Protocol Specification For Interfacing to Data Communication Networks;
- International Electrotechnical Commission (IEC) 60870-6/ Telecontrol Application Service Element (TASE).2/ Inter-Control Centre Communications Protocol (ICCP): Control Center to Control Center Information Exchanges;

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[27] http://www.ferc.gov/EventCalendar/Files/20110719143912-RM11-2-000.pdf.

[28] These standards include IEC 61850, 61970, 61968, 60870-6, and 62351.

[29] http://www.nist.gov/smartgrid/upload/nistir-7628_total.pdf.

[30] http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/NISTStandardsSummaries.

- IEC 61850: Communications Networks and Systems for Power Utility Automation;
- IEC 61968: Common Information Model (CIM) and Messaging Interfaces for Distribution Management;
- IEC 62351: Power Systems Management and Associated Information Exchange - Data and Communications Security, Parts 1 through 7;
- SAE J2847/1: Communication between Plug-in Vehicles and the Utility Grid.

In the newly released draft version of the NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 2.0, NIST introduced a new Smart Grid devices testing and certification framework that provides details on an assessment of existing Smart Grid standards testing programs. This framework is developed by the SGTCC (Smart Grid Testing and Certification Committee). The NIST publication provides a high-level guidance for the development of a testing and certification framework and includes an operational framework for how testing and certification of the Smart Grid devices will be conducted. It also introduces interoperability process reference manual and the interoperability maturity assessment model. The framework discussion is followed by a comprehensive roadmap that addresses further development and implementation requirements. Upon adoption of this framework, NIST expects that feedback from the standard conformance and interoperability test results will become an important part of the future standard identification process. Such as, the deficiencies and gaps of a standard, identified through the interoperability testing and certification process, may potentially help determine whether a candidate standard needs further review.

Future Standards Development

As stated in the newly released draft version of the NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 2.0, NIST and SGIP (Smart Grid Interoperability Panel) will:

- Continue to execute the Priority Action Plans (PAPs) presently under way until their objectives to fill identified gaps in the standards portfolio have been accomplished. As new gaps and requirements are identified, the SGIP will continue to initiate PAPs to address them.
- Use the lessons learned from the American Recovery and Reinvestment Act (ARRA) funded Smart Grid Investment Grant (SGIG) projects to further identify the gaps and shortcomings of the standards upon which the Smart Grid technologies are based. NIST and the SGIP will work with other stakeholders to fill the gaps and improve the standards that form the foundation of the Smart Grid.
- Continue to fully populate the SGIP Catalog of Standards and ensure robust architectural and cyber security reviews of the standards. The cyber security guidelines will be kept up to date to stay ahead of emerging new threats. Efforts will continue to partner with the private sector as it establishes testing and certification programs consistent with the SGIP testing and certification framework.

Per the draft version of the NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 2.0, future SGIP activities will include:

- **SEP1.x Migration (Priority Action Plan(PAP) 18):** PAP 18 was formed to develop specific requirements that must be met to allow for the coexistence of SEP 1.x and 2.0 and to support the migration of SEP 1.x implementations to SEP 2.0. This effort assumes that the meters themselves are capable of running SEP 1.x or SEP 2.0 via remote firmware upgrade and the focus of the effort is on the events leading up to and impact of such an upgrade. The primary outputs of the PAP 18 are:
    - A white paper that summarizes the key issues with migration from SEP 1.x to SEP 2.0 and makes specific recommendations; and
    - A requirements document that will be submitted to the ZigBee Alliance for consideration in developing the technology specific recommendations, solutions, and any required changes to the SEP 2.0 specifications themselves.
- **New Distributed Renewables, Generators, and Storage (DRGS) Domain Expert Working Group (DEWG):** The SGIP has created this new DEWG to identify standards and interoperability issues and gaps related to the integration of distributed renewable/clean energy generators and electric storage, and to initiate priority action plans and task groups to address these issues and gaps. The Smart Grid functions of particular importance are identified as:
    - Enabling grid integration of intermittent distributed renewable generators;
    - Enabling distributed generator/storage devices to provide valuable grid supportive ancillary services;
    - Preventing unintentional islanding of clustered distributed generator/storage devices; and
    - Providing acceptable distributed generator/storage device fault response without cascading events.

  The DRGS DEWG will also address communication needed for distributed control of generator/storage devices within microgrids, including the interaction of devices having high-bandwidth power electronics-based grid interfaces (such as photovoltaic generators and battery storage) with rotating machine devices having high intrinsic inertia.
- **Addition of Reliability and Implementation Inputs to Catalog of Standards Life Cycle Process:** The SGIP is considering methods to solicit input and guidance from Smart Grid stakeholders regarding reliability and implementation issues raised by standards completing the Catalog of Standards (CoS) life cycle process. Stakeholders engaged in this fashion are expected to review documents and standards that are considered for addition to the CoS. These reviews are expected to provide analysis to industry and regulators of the potential impacts to system reliability and implementation.

In 2011, the CSWG updated its Three-Year Plan,[31] which describes how the CSWG will continue to implement the strategy defined in NISTIR 7628 and address the outstanding issues and remaining tasks. Some of the future CSWG activities that are highlighted in the draft version of the NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 2.0, are :

- **Risk Management Framework:** The CSWG is participating in a public-private initiative led by the NIST, the North American Electric Reliability Corporation (NERC), and the CSWG to develop a harmonized energy sector enterprise-wide risk management process, based on organization missions, investments, and stakeholder priorities. This guideline is expected to leverage the NISTIR 7628, Guidelines for Smart Grid Cyber security,[32] the NERC Critical Infrastructure Protection (CIP) reliability standards,[33] NIST cyber security publications (especially NIST SP 800-39, Managing Information Security Risk: Organization, Mission, and Information System View[34],), the National Infrastructure Protection Plan (NIPP) Risk Management Framework,[35] and lessons learned within the federal government and private industry.
- **Cyber-Physical Attack Research:** The CSWG is planning to actively pursue collaborations with other organizations to address the impact of coordinated cyber-physical attacks. Assessing the impact of such attacks will require expertise in cyber security, physical security, and the electric infrastructure. And, the CSWG is planning to collaborate with other stakeholders to identify this challenge and take steps to mitigate the potential impact of these types of attacks on the Smart Grid.
- **Smart Grid Cyber security Test Guidance:** CSWG will continue to expand coordination with the SGTCC (Smart Grid Testing and Certification Committee) to develop guidance and recommendations on Smart Grid conformance, interoperability, and cyber security testing.
- **NISTIR 7628 Updates:** The CSWG will continue to review and assess the new and updated existing standards to determine how these changes should be reflected in NISTIR 7628. The CSWG will review NISTIR 7628 approximately every 18 months and the topics under consideration for a future update of NISTIR 7628 include:
    - Creating a matrix of privacy concerns in multiple settings and expanding the section on the Smart Grid impact on privacy concerns;

[31] http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/CSWGRoadmap.

[32] http://csrc.nist.gov/publications/nistir/ir7628/introduction-to-nistir-7628.pdf.

[33] http://www.nerc.com/page.php?cid=2|20.

[34] http://csrc.nist.gov/publications/nistpubs/800-39/SP800-39-final.pdf.

[35] http://www.dhs.gov/files/programs/editorial_0827.shtm#0.

- Initiating a task within the SGIP SGAC to ensure the conceptual security architecture is harmonized with the SGAC conceptual architecture during its development; and
- Adding additional high-level cyber security requirements that are identified during the standards reviews and supplemental work that the subgroups undertake.

The testing and certification framework discussion also includes a number of activities that NIST and the SGTCC (Smart Grid Testing and Certification Committee) are working on to resolve related issues for the further development and implementation of this framework. These activities include:

- Developing Interoperability Testing and Certification Authority (ITCA) evaluation processes;
- Developing end-to-end or system testing methodology;
- Performing outreach, marketing, and education;
- Collaborating with the Cyber security Working Group (CSWG) on security testing;
- Provide ongoing support to ITCAs by SGTCC members;
- Preparing for the transition; and
- Prioritizing Test Program needs.

The SGTCC is planning to transition towards support of the implementation activities associated with the testing and the certification framework. NIST will continue to work with SGIP, the SGTCC, and industry stakeholders in refining the framework and providing necessary support for its implementation.

Suggested Approaches for POUs

Cyber Security

Cyber security is of the utmost importance to a sustainable modern grid. The Smart Grid involves the automation of several manual processes and procedures. It does so, in part, by overlaying a communications infrastructure on top of the grid, allowing utilities to make better decisions about energy usage and spot potential failures more quickly. Cyber security helps to augment reliability where automated solutions and advanced processes break down. This reliability is critical to every utility and may be the most important facet of energy operations, because unreliability results in utilities' inability to provide power. Consumers may not notice the automation of the grid, but they will notice if the lights go out.

Unfortunately, in most cases today, and as also described earlier, security standards and regulations fall short of what is needed to provide maximum assurance of Smart Grid reliability from a cyber security perspective.

Those California POUs that filed SB-17 Smart Grid Deployment Plans or ARRA grant recipients, all have comprehensive cyber security plans to address the risks associated with cyber security and the interoperability and standard issues that arise during the Smart Grid deployment. These plans include, among other things, various approaches to include cyber security in the vendor selections process, upgrade strategies, a description of compliance with the NIST standards and associated mitigation strategies. A summary of a few key utilities' plans are highlighted below.

SMUD: In its Smart Grid Deployment Plan, SMUD indicated it plans to identify and address cyber security issues to prevent potential attacks on individual customers or the system as a whole. The cyber security project will include intrusion detection system enhancements, vulnerability management, security event information management, and ongoing cyber security assessments and budgeted $4.4 million dollars for the effort.

BWP: Burbank's Smart Grid Deployment Plan includes a sound approach to analyze Smart Grid device interoperability and the application of procedures and practices involving interface identification, specification, testing, and lifecycle management. BWP plans to meet these requirements through its Mission Critical Asset Protection Program.

LADWP: LADWP plans to include a grid resilience effort to show how the Smart Grid can operate resiliently against physical and cyber attack, operational effectiveness effort to demonstrate a complete cyber security testing approach for components and installed systems and an effort to redefine of cyber security measures that address the expansion of this perimeter by Smart Grid technologies to the meter in residential and commercial sites.

Analyzing the Smart Grid for Vulnerabilities

Categorizing what impacts systems are vulnerable to is generally the first step in the analysis of any architecture for security posture. Knowing what the impacts may be informs the analyst as to how much security needs to be applied to reduce risk to an acceptable level. Moreover, the more security that is added, the more the probability of a successful attack is reduced. This is the primary benefit of requiring utilities to adhere to guidance with regard to the integration of security in Smart Grid architectures.

However, just because security is implemented does not mean the architecture is safe. In the security world, implementing security controls is associated with managing risk to the infrastructure. Since the impact of an event can be easily determined and measured, the level of criticality also can be determined fairly easily. If no security is applied, the likelihood increases that an event will happen. Using the traditional risk model of impact times probability, a utility can associate a risk level with the Smart Grid architecture. However, given the dearth of reliable incident data, this process is often very subjective and requires a significant amount of extrapolation.

Utilities must measure risk to devise mechanisms to manage the risk. Moreover, the only way to measure risk is to determine, to some extent, the probability of an attack. In high-impact systems such as AMI or other Smart Grid elements, utilities should understand what security controls are available, implemented and not implemented. This provides utilities with an understanding of what their risk level is so they may provide informed assurance to their consumers that they are making an effort to support reliability from a cyber security perspective.

Because security can be quite ambiguous and interpreted differently without standardization, it will be increasingly important to standardize controls that are necessary to reduce risk. The best way for utilities to provide assurance that their cyber security risk is being properly managed is to require their Smart Grid elements to adhere to a standard set of security principles.

Going Forward

Among other benefits, Smart Grid also presents an opportunity to improve reliability and security rather than put the grid at greater risk, but to do so requires constant vigilance and proactive steps to address new risks associated with adoption of new technologies and standards. This is all possible if everyone works together to solve today's challenges rather than those of yesterday.

In order to help identify, measure, and manage risks to California's POU infrastructure and Smart Grid deployments, state level efforts should focus on three principle areas as it relates to adoption of Smart Grid technologies by POUs.

1) **Define the Problem.** What already existing systems have had technology audits performed recently as it relates to conformance to the generally accepted principles and standards for enabling deployment of Smart Grid technologies? What were the findings? There is no substitute for clarity around scope, function, and impact of generally accepted principles and standards when identifying and managing risks associated to the implementation of Smart Grid technologies.

2) **Assess the Current State of Standards Development Efforts.** Engage with energy operators, technology providers and regulators to understand what standards are in place, and what the consequence of failing to meet those standards are. What new developments are on the horizon? How risk management and controls related to adoption of standards should be integrated into the entire Smart Grid project lifecycle? How are they applying technical, operational, and management controls according to best practices?

3) **Engage in an ongoing Dialogue.** Develop an ongoing discussion and interaction with the POUs in the State to engage them more in the standards development process by working with manufacturers and the Energy Commission to provide data and pilot demonstrations. Create a platform for information sharing and continued discussion between the POUs and the Energy Commission around enabling Smart Grid technologies and standards, the state of implementation of technologies, standards and pilot demonstrations, lessons learned, the evolving risks, impacts, and possibilities.

By engaging in these three activities, the Energy Commission will:

- Gain an understanding of the various POU initiatives as it relates to Smart Grid technology deployments

- Understand the risks and impacts of failing to meet standards that could compromise the deployment of Smart Grid technologies from POU perspective
- Understand the current risk and impact posture of the infrastructure, and its consequence for the state
- Identify areas where the State can help manage the risk and impact from a compromise to enabling energy infrastructure.

Technology Gap Analysis

California POUs Gap Analysis

In light of the above discussion on Smart Grid enabling technologies and use cases, and the current state technology implementation analysis conducted in Chapter 3, SAIC identified the technology gaps for the California POU's under the following four categories:

- Foundational Information Technology and Communication Systems
- Customer Service and Demand Response
- Distribution and Substation Automation
- Distributed Energy Resources

The gap analysis is conducted for the Followers and the Leaders categories, as defined in Chapter 3, separately.

Foundational Information Technology and Communication Systems Gaps

Table 15 summarizes the California POUs' gaps in implementation of the enterprise IT architecture, foundational IT systems and the enterprise communication infrastructure. In the enterprise IT architecture area, the Followers still lack the necessary IT architecture to even support the current business processes and information flows and the vision, policies and standards around future IT architecture that will enable implementation of new Smart Grids technologies and applications, while the Leaders seem to have the necessary vision and plans in place to further improve their IT architecture but are still lacking sufficient adaptation of event-driven architectures, standards and protocols that will ensure the longevity of their current investments.

In the foundational IT systems area, the Followers still lack the deployment of foundational IT systems such as geographical information systems (GIS), engineering analysis (EA) tools and work and asset management systems and often rely heavily on manual processes, hardcopy documents and stand-alone data repositories. The Followers also often suffer from the implementation of legacy and custom build systems that result in intensive point-to-point integration efforts and batch transactions. On the other hand, the Leaders often have most of the foundational IT systems already deployed with few exceptions and achieved integration among these systems to some degree, but they still lack the sufficient level of integration and information sharing between the utility systems and staff for true Smart Grid operations. However, most are in the process of further improving their connectivity models and the integrations among their systems through the implementation of service-oriented architectures (SOA) and enterprise service buses (ESBs).

In the Enterprise Communications Infrastructure area, the Followers still often lack the sufficient investment in communication infrastructures and the adoption of necessary communication standards and technologies. On the other hand, the Leaders are in the process of expanding their deployment of communication infrastructures for advanced metering infrastructures (AMI), and substation and distribution automation communication infrastructures. However, functional separation still exists among the existing communication networks and the continued efforts will still be needed to address the vulnerabilities and capabilities of various communication technologies for different types of Smart Grid applications.

Table 15: California POUs Foundational IT and Communication Systems Gaps

	FOLLOWERS	LEADERS
Enterprise IT Architecture Gaps	• Lack of enterprise IT architecture and vision • Lack of enterprise IT policies / standards • Existing network architecture does not easily support application of new Smart Grid technologies • Lack of guidelines in determining security requirements • Existing IT architecture often does not support business and information flows	• System architectures has not been sufficiently standardized to enable plug-and-play integration and scalability • Insufficient adoption of object oriented architectures / standards / protocols that are critical for the longevity of the Smart Grid investments. • In the process of deploying event-driven IT architectures such as SOA and ESBs
Foundational IT Systems Gaps	• Lack of deployment of foundational systems - GIS, EA, OMS, WMS, AMS • Lack of integration among the foundational systems if deployed • If exists, integrations between systems are often point-to-point involving batch transactions • Relies heavily on stand-alone MS Excel and Ms Access Databases • Multiple versions of data kept by different staff/groups in stand-alone databases • Legacy and custom build systems such as CIS, asset management systems do not support easy integration and interoperability standards • Insufficient implementation of GIS applications - still rely heavily on hardcopy circuit maps	• Most of the foundational IT systems are deployed with few exceptions such as MWFM and EMS • Integration among the key foundational systems exists to some degree but still needs further improvement as new systems are deployed for thorough Smart Grid operations • Deficiencies still exist in GIS and EA models with respect to asset / customer connectivity. • Insufficient integration between GIS, OMS, and SCADA systems • Insufficient information sharing between the field and utility personnel.

	FOLLOWERS	LEADERS
Enterprise Communication Infrastructure Gaps	• Lack of investment in communication infrastructures • Separate communication networks for different purposes - AMI, DA, SA • Lack of adoption of communication standards and technologies	• In the process of investing in SCADA, SA/DA and AMI/HAN communication networks however functional separation still exists among the existing communication networks • The capabilities and vulnerabilities of various communication technologies such as wireless technologies and IP-based networks are not well defined for different types of Smart Grid enabling applications • Continued efforts will be needed to adopt / map the object models to various communication protocols.

AMI: Advanced Metering Infrastructure
AMS: Asset Management System
CIS: Customer Information System
DA: Distribution Automation
EA: Engineering Analysis
EMS: Energy Management System
ESB: Enterprise Service Bus
GIS: Geographical Information Systems
HAN: Home Area Network
IT: Information Technology
MWFM: Mobile Workforce Management System
OMS: Outage Management System
SA: Substation Automation
SCADA: Supervisory Control and Data Acquisition
SOA: Service Oriented Architecture
WMS: Work Management System

Customer Service and Demand Response Gaps

Table 16 summarizes the California POUs' gaps in the implementation of enabling technologies and programs for customer service and demand response. In the enabling technologies area, the Followers still lack the necessary vision and plans with respect to the implementation of customer service and demand response related technologies such as advanced metering infrastructures, 2-way communication networks, in-home displays (IHDs) and demand and direct load control technologies. The Followers are not even conducting enough experimentation with such technologies either. On the other hand, the Leaders are in the process of deploying and experimenting with customer service and demand response related technologies, however these systems are not yet fully functional and integrated yet. In addition, the information models/standards/protocols for demand response / direct load control (DR/DLC) and home-area network (HAN) based devices/appliances and the compatibility of various communication networks with customer side devices, appliances and applications are not well defined yet to ensure successful adoption and participation in DR programs.

From the enabling programs perspectives, the Followers still lack sufficient deployment of customer service programs & rate structures to encourage off-peak usage, while the Leaders also still lack the experience with new customer service needs and programs with respect to customer empowerment and demand response, they are either planning to or in the process of developing and experimenting with such programs and dynamic rate structures.

Table 16: California POUs Customer Service and Demand Response Gaps

	FOLLOWERS	LEADERS
Customer Service & DR Technologies	• Lack of Smart Grid plans / visions with respect to Customer Service and DR • Lack of deployment/experimentation of smart metering technologies AMI/AMR and MDMS • Lack of experimentation with 2-way communication networks for service connect/disconnect and tamper/outage detection • Lack of experimentation with DR /DLC technologies such as IHDs, HANs, PCTs, and so forth.	• Deployment of smart metering technologies AMI and MDMS and two-way communication networks are underway but not fully integrated to the other utility systems yet. • Either in the process of deploying or planning to deploy customer web portals but the functionality of the web portals is still limited and insufficient for true customer empowerment. • Deployment of DR/DLC technologies such as IHDs, HANs, PCTs and proof-of-concept projects with respect to these technologies are underway but not functional yet. • Either in the process of deploying or planning to deploy energy / demand management and response systems • Lack of installation of smart appliances that can participate in DR events • Lack of information models/standards/protocols for DR/DLC and HAN-based devices/appliances so that they can participate in mitigation of system reliability events. • Compatibility of various communication networks with customer side devices, appliances and applications are not well defined yet to ensure successful adoption and participation in DR programs.
Customer Service & DR Programs	• Lack of programs to encourage off-peak usage • Lack of customer service programs & rate structures to enable DR and customer choice • Lack of experimentation with customer service programs & dynamic rate programs • Lack of incentives to encourage customers to participate in DR/DLC programs • Lack of incentives to encourage customers to adopt DR/DLC technologies	• Planning to or in the process of developing new customer programs and rate structures for DR • Lack of customer adoption of DR/DLC technologies and lack of participation in DR/DLC programs • Lack of incentives to encourage customers to acquire smart devices/appliances • Lack of experience with new customer service needs and programs

AMI: Advanced Metering Infrastructure
AMR: Advanced Meter Reading
DR/DLC: Demand Response / Direct Load Control
HAN: Home Area Network
IHD: In-Home Display
MDMS: Meter Data Management System
PCTs: Programmable Communicating Thermostats

Distribution and Substation Automation Gaps

Table 17 summarizes the California POUs' gaps in the implementation of enabling technologies and programs for distribution and substation automation. In the enabling technologies area, the Followers still lack the necessary vision and plans with respect to the implementation of distribution and substation automated related devices and technologies and the two-way communication networks for remote monitoring and control of such devices and technologies. The Followers still lack even the sufficient deployment of substation automation and SCADA in the distribution substations and thus the integration between SCADA and few distribution automation devices that are deployed or being experimented with in the field. On the other hand, the Leaders are in the process of expanding SCADA and substation automation to all the distribution substations and their distribution communication networks. They are also in the process of expanding deployment of distribution automation devices and technologies in the field. However, the Leaders still currently have limited monitoring and control capabilities of distribution/substation automation devices through SCADA in support of feeder configuration and voltage management. The Leaders are also in the process of enhancing/ developing/deploying engineering analysis tools, but still lack the operational systems and applications that will enable dynamic and integrated control of distribution and substation automation devices.

From the enabling programs perspectives, the Followers still lack sufficient processes and procedures for improving grid efficiency and asset monitoring, management and maintenance programs. The Followers lack the visibility of distribution operations in real-time such as outage management/ restoration efforts, switching, fault detection, and voltage management. They conduct limited system and engineering analysis for planning and growth, but not necessarily for the application of distribution automation devices mitigating the impact of demand response, distributed generation and energy resources. The Leaders have achieved limited visibility of distribution operations through integrations between, SCADA, outage management and geographical information systems. They also have limited implementation of condition-/ performance- based asset management programs for key distribution and substation assets, and are in the process of developing distribution system automation and communication standards. However, the Leaders still lack the system and engineering analysis capabilities for advanced and integrated system planning and forecasting, including the impact of demand response, distributed generation and energy resources.

Table 17: California POUs Distribution and Substation Automation Gaps

	FOLLOWERS	LEADERS
DA/SA Technologies	• Lack of Smart Grid plans / visions with respect to DA/SA • Lack of deployment/experimentation of 2-way distribution communication networks • Lack of deployment/experimentation of distribution/substation automation devices/ technologies • Lack of deployment/experimentation of asset monitoring devices and sensors for asset management • Lack of deployment/experimentation of automated capacitors, load tap changes and voltage regulators for voltage management • Lack of deployment/experimentation of automated switches, reclosers for feeder reconfiguration • Lack of deployment/experimentation of fault indicators, smart relays, reclosers and indicators for fault detection and isolation • Lack of deployment of SCADA and SA in the distribution substations • Lack of integration between SCADA and DA devices in the field for remote monitoring and control • Lack of implementation of system/engineering analysis applications	• In the process of expanding the distribution communication networks • In the process of expanding SCADA and SA to all the distribution substations • Incomplete distribution system automation and communication standards. • Limited deployment of monitoring devices and sensors on key assets • In the process of expanding deployment of automated switches and reclosers to all feeders • In the process of expanding deployment of automated capacitors, load tap changes and voltage regulators to all circuits • Limited monitoring and control of distribution/substation automation devices through SCADA are enabled in support of feeder configuration and voltage management • Lack of operational systems, applications that will enable dynamic and integrated control of distribution/substation automation devices • In the process of enhancing/developing /deploying engineering analysis tools that will conduct real-time analysis and optimization including the impact of DER/DG and DR resources
DA/SA Applications	• Lack of utility processes and procedures for improving grid efficiency. • Lack of system/engineering analysis for system planning, growth and application of DA devices • Lack of system/engineering analysis analyzing the impact of DR/DG and DER • Insufficient asset monitoring, management and maintenance programs • Lack of condition-based/performance based asset management programs • Lack of visibility of distribution operations in real-time; outage management/ restoration, switching, fault detection, voltage management and so forth.	• Distribution system automation and communication standards are under development. • Lack of system/engineering analysis for advanced system planning and forecasting including the impact of DER/DG and DR resources • Limited implementation of condition-based/performance based asset management programs for key distribution/substation assets. • Limited visibility of distribution operations is achieved through integrations between, SCADA, OMS and GIS.

DA: Distribution Automation
DER: Distributed Energy Resources
DG: Distributed Generation
DR: Demand Response
GIS: Geographical Information Systems
OMS: Outage Management System
SA: Substation Automation
SCADA: Supervisory Control and Data Acquisition

Distributed Energy Resources Gaps

Table 18 summarizes the California POUs' gaps in the implementation of enabling technologies and programs for deployment and integration of distributed generation and energy resources. In the enabling technologies area, the Followers still lack the necessary vision and plans with respect to the integration of distributed energy resources and generation. They also do not conduct enough experimentation with DER/DG technologies such as storage systems, and PEVs, and the DER/DG integration technologies such as power inverter technologies. On the other hand, the Leaders have limited deployment of storage systems and PEV charging stations; however not-well defined information models / standards / protocols for interaction with DER/DG and PEVs are hampering their progress. The Leaders also currently have limited monitoring and control capabilities of distribution/substation automation devices through SCADA in support of feeder configuration and voltage management. The Leaders are also still in the process of enhancing/ developing/deploying engineering analysis tools to understand impact of intermittent DER/DG resources on the grid, but still lack the operational systems and applications that will enable dynamic and integrated control of intermittent resources. And, neither the leaders nor the followers currently have control of customer side generation resources or PEVs.

With respect to the programs, both groups still lack programs and/or rate structures to encourage PEV customers to charge during off-peak hours or to enable residential customers to sell excess generation back to grid.

Table 18: California POUs Distributed Energy Resources Gaps

	FOLLOWERS	LEADERS
DER Technologies	• Lack of Smart Grid plans / visions with respect to DER/DG integration • Lack of deployment/experimentation of DER/DG technologies such as storage systems, PEVs • Lack of experimentation with DER/DG integration technologies such as power inverter technologies • Lack of deployment of 2-way communication networks to enable monitoring and control of DER/DG resources • Lack of visibility of customer side DER/DG resources and PEV charging	• Limited deployment of storage systems and PEV charging stations • Lack of information models / standards / protocols for interaction with DER/DG and PEVs. • Lack of energy management systems and/or system operations software to support monitoring, control and dispatch of intermittent resources • Very limited experimentation with DER/DG integration technologies such as power inverter technologies • Lack of advanced analysis and forecasting tools to understand impact of intermittent DER/DG resources on the grid • No control of customer side DER/DG and PEV charging stations • Insufficient reliability and protection analysis to assess the impact of DER/DG resources on the grid
DER Programs	• Lack of rate programs to encourage PEV customers to charge during off-peak hours • Lack of rate structures and programs such as feed-in-tariffs to enable customers to sell excess generation back to grid. • Lack of incentives to encourage customers to deploy DER/DG resources • Lack of analysis to assess the impact of DER/DG resources on the grid	• Lack of rate programs to encourage PEV customers to charge during off-peak hours • Lack of rate structures and programs to enable residential customers sell excess generation back to grid.

DER: Distributed Energy Resources
DG: Distributed Generation
PEV: Plug-in Electric Vehicle

Discussion of Gaps between 2011 and 2020

Smart Grid is often conceived as electrical and electronic devices, distributed throughout the electric infrastructure, communicating and controlling things to optimize it all. That's a reasonable starting view. But Smart Grid requires and includes numerous other things to make it work. Technical standards are central to making those devices economically practical. And policies and procedures are essential to enable their use. The electrical and electronic parts of Smart Grid that are available now are capable of most of the functions envisioned for the year 2020. The gaps between what is available now and what is needed to fulfill the vision of 2020 are greatest in the "soft" parts of Smart Grid: the standards, policies, procedures, algorithms.

Electronics and Firmware

The current state of electrical and electronic devices supporting Smart Grid is significantly ahead of the other elements we'll discuss here. Available devices could be capable of much higher level of automation and integration, if only the software, supporting IT, policies, and procedures could keep up. For example, once a “dumb” feeder switch is combined with an intelligent electronic device (IED) to make it a smart switch, it is capable of doing whatever it is commanded to do, including a wide range of automated feeder monitoring, protection and restoration functions.

Another example: While it may be incorrect to call solar and wind generation technologies “mature,” they certainly are no longer emerging. Both are readily available from multiple suppliers, listed and priced in catalogs, produced in volume, and delivered in commercial time-frames. The electrical and electronic aspects of these renewable sources are well-enough developed for large-scale application. But coordinating the short-term variability of their output with the larger grid is a serious challenge, and that capability has barely reached the “emerging” stage. Burbank Water and Power is currently implementing an advanced energy demand management system that will combine intermittent sources of supply, like solar and wind, with energy storage and demand response, another variable resource, to be able to maximize the financial and reliability value of intermittent resources.

The same can be said of most of the Smart Grid functions now envisioned for the year 2020: The hardware and functional software of many individual devices is sufficiently developed and available to support a highly integrated Smart Grid. But the “technologies” needed for that integration—the operating logic, algorithms and procedures, and the corporate and public the policies—are far short of what will be needed. The distribution management system (DMS) described in the substation section above is a good example of an initial integration approach with limited scope that minimizes policy issues by focusing on purely engineering operations. But many other Smart Grid functions have broader ramifications. Discussion follows below.

Algorithms, Policy and Procedure

For the smart switch example above, implementing all those functions requires utility engineers to figure out how to coordinate the actions of that switch with other switches and other devices, not only to correctly automate the imagined functions, but also to maintain safety and avoid doing damage by mistake. Developing the control algorithms, the automation-specific “select before operate” rules, coordination policies, operating procedures, and regulatory policies associated with many circumstances (storm, outage, supply crisis, civil emergency, and so forth.) will take time, public dialog, and operating experience. It won’t happen quickly.

Many of the unaddressed and unresolved questions have not yet been identified. For example, as part of the American Recovery and Reinvestment Act of 2009 (ARRA) funding, a concerted effort was launched in Energy Assurance to identify needed policies and procedures to assure America’s energy supply in times of crisis. Smart Grid will be a productive resource for this. One example is the service switch often included in smart meters. If an emergency (weather disaster, terrorist act, nuclear calamity, and so forth.) requires a large scale load shed action, the presence of service switches makes it possible to shed only residential loads, without compromising supply to critical facilities such as hospitals, police and fire departments, key government and communication facilities, and so forth.

The logic of this option is plain enough, and the technical capability obviously is there, already deployed at a few million meters in California. But many questions that must be resolved have not been answered, or even asked. What policies apply to such a load shed action? Which "residential" facilities can be shed and which must be excepted from the shed action? Certainly the home of someone dependent on electricity for life support (such as a home dialysis patient) must be excepted. But what about a small (or home-based) business with a switch-equipped "residential" meter? Must that business suffer the economic loss of being shed while businesses in office buildings are not shed? What are the degrees of emergency, and the corresponding stages of load shed? And who will be denied power in each?

The above example related to the residential service switch is just one of many. Most of these questions may not become apparent until utilities examine the operating alternatives that new Smart Grid automation makes possible.

Summary of Technology Gaps

In summary, gaps in hard technology will not be the limiting factor in achieving the Smart Grid vision of 2020 or any intermediate state. Technology evolution has created the opportunity to implement Smart Grid, and will continue to lead, not lag, the opportunities. The gaps are first in technical integration of diverse operating technologies, and these gaps are exacerbated by the slow evolution of technical standards. These gaps are quickly followed by gaps in operating procedure and policy, and in the public policy dilemmas that the new operations will foster. Focused effort to envision and prioritize the Smart Grid opportunities will help identify and address these issues early.

Smart Grid Technology Has A Long Life

Any major commitment to a Smart Grid technology raises a similarly major concern: Obsolescence.

> Question: How can we know that a technology we invest in now, and that we must use for 15 years to fulfill the business case and achieve an acceptable return, will remain technically and operationally viable for 15 years?
>
> Answer: We can't know this. But we have a basis for confidence.

Technology suppliers respond to economic opportunity and produce solutions when they can make money doing it. If an appreciable number of utilities find themselves with apparently obsolete technologies, and facing operational needs they can meet only with untenable expenditures, the community of technology developers is likely to discover a solution. This has happened repeatedly, and is a basis for believing that we are likely to get good value from a competent technology choice over the long term, as long as we are not the only ones making that choice. The following example illustrates the elements of the concern.

Suppose that in year 2000 a utility found that it had a positive 20-year business case for basic meter automation. The utility then invested in drive-by meter reading, of the kind prominently provided by Itron. Today, in 2011, that system is just over half way through its assumed depreciation life. Now further suppose that utility finds in 2011 that its future ability to sustain reliable service depends on implementing innovative pricing programs (such as peak time rebate) that require collecting hourly data from all accounts. The drive-by system is unable to gather hourly data from all meters. What can this utility do?

The utility has several options.

- Discuss with the supplier, how to upgrade only those customer accounts that will participate in the hourly program(s). If only a small or moderate fraction of customers will participate, this may be a viable approach.
- Carefully examine the business case for completely replacing the existing system, in spite of its depreciation status. If the new programs will produce high value, this may be acceptable, even attractive, notwithstanding the financial impacts of the shortened existing system life.
- Leverage other new technology options to gather data and reach customers.

The third option is the one that, if numerous utilities are in the same situation, will be addressed by technology providers. For example, several providers make receivers that can receive the "bubble up" radio transmissions from drive-by meters that contain the register reading. These typically occur every few seconds, making it practical to gather full load profile information. If the customer agrees to connect to the utility via the customer's Internet service—say, as part of the agreement to participate in the dynamic rate program—the utility can send signals to the customer and receive meter data via the Internet. Except that this does not provide a remotely operable service switch included in many smart meters, this approach accomplishes most of what can be done with full two-way smart metering.

As this example demonstrates, there are many ways to accomplish new goals, and the limitations of old technologies are often readily overcome by applying new technologies without replacing the old ones. If there is a significant market for the new technologies, the business case for this approach can be very attractive. Another conclusion of this example is: A utility that chooses a Smart Grid technology path chosen by no other utilities elevates its risk of later suffering a financial challenge due to technology obsolescence.

Vendors

It is reasonable to expect that the firms that make the elements of Smart Grid will continue to evolve at a pace and in a direction that supports implementation of the highest value aspects of Smart Grid.

A quarter century ago, "distribution automation" was where Smart Grid is now. Trade publications were abuzz about how new communication and control technologies will enable remote monitoring and operation of distribution switches, capacitors, and other devices, and how this will improve reliability and lower costs. Companies were founded to make and sell the "remote terminal units" and other devices that supported these functions. The systems were monolithic. That is, a capacitor control system did only capacitor control, and all operating integration with other utility functions occurred only in the minds of and at the hands of the operators.

As automation technology evolved, the monolithic systems have become more integrated with other utility systems. Correspondingly, the companies that make them have merged and expanded to offer more diverse, and more integrated, systems.

In metering, every major residential meter manufacturer was part of a large international company less than 10 years ago. Most of the major meter automation (AMR/AMI) firms were separate from the meter manufacturing firms, and offered meter communication modules that fit in all major meters. We have seen a substantial consolidation since then. Meter manufacturing was spun out of all the large international companies (except GE) into smaller, more focused companies that now also (again, except GE) make meter automation/ communication systems. In the last five years, these firms have expanded the scope of their Smart Grid involvement by acquiring software companies that produce utility IT systems for meter data management and other core IT functions. And some (such as Itron, Landis+Gyr) have acquired other companies that further expand their abilities to provide integrated utility automation systems.

The same is true in other Smart Grid domains. A standout example is Cooper's acquisition of Cannon Technologies with all its distribution / SCADA capability. Another is electrical equipment maker Schneider Electric, which has acquired Telvent (grid operating software), Lee Technologies (24/7 data centers), and Summit Energy Services (energy procurement).

This trend is likely to continue, and the vendor community will be capable of developing and supporting Smart Grid technology at a pace greater than the utility industry is able to deploy it. Some of the companies that are prominent now (many named in the preceding sections), will continue as independent firms. But others will be acquired to form larger firms capable of the technical integration needed to implement more advanced Smart Grid functions.

Disruptive Developments

In pondering the gaps between present Smart Grid technologies, vendor capabilities, and standards and those needed to fulfill the vision of 2020, we have no practical way to anticipate disruptive developments that may intervene. In 2002, a few managers at the Electric Power Research Institute (EPRI) struggled to attract attendance at meetings about how to integrate the electric grid. The following summer, cascading grid failures darkened the northeastern quadrant of the U.S. That cascade could have been avoided by precisely the integration EPRI was espousing, and EPRI found an eager audience in the nation after that. The course of the industry was altered by that sequence of operating failure and technical opportunity, followed by major public policy and funding shifts in favor of what we now call Smart Grid.

That disruptive event was an operating failure, related to weather and existing infrastructure. Disruptive events can occur in technology development, too, sometimes associated with policy changes. A May 1985 decision by the Federal Communications Commission (FCC) authorizing unlicensed public use of certain 900 MHz spectrum spawned pervasive changes in many industries. In the utility sector, this led to development of unlicensed meter reading systems that evolved into several of today's AMI systems.

Another communication technology may spark similarly broad changes. "Ultra wideband" (UWB) radio technology promises to substantially improve performance and reduce costs of wide-area multi-point systems such as Smart Grid. If FCC rules are changed to allow UWB, this could expand the available Smart Grid products and functionality beyond what is now anticipated.

CHAPTER 5:
Smart Grid Business Case Framework

This section discusses the cost and benefits associated with utility Smart Grid investments and provides a framework for the economic evaluation of costs and benefits of Smart Grid applications for publicly owned utilities (POUs). The framework serves as a guideline that will provide a starting point for POU's to conduct more detailed assessments of their specific Smart Grid initiatives and provides a broad analysis of primary Smart Grid applications.

The business case framework is an Excel based spreadsheet and should be used in conjunction with this section to fully understand the benefits and associated cost of the technologies required to gain the benefits specified.

The costs and benefits outlined herein have been developed through research of publicly available data (mainly EPRI, NETL, NREL, the Energy Commission, the DOE, and the Brattle Group) as well as information used in detailed business case models we have developed for other utility clients.

Business Case Framework Methodology

The cost benefit framework is not a detailed business case analysis and therefore should not be used alone to justify utility Smart Grid investments. A number of assumptions have been made in the development of this framework which may or may not apply to all POUs. The framework should be used as a tool to understand the high-level cost benefit analysis of relevant Smart Grid systems and applications (previously described in Chapter 4 above) which are presented in the context of California's energy policies and POU drivers.

The framework is organized by the Smart Grid Use Cases described in Chapter 4. Each Use Case has a number of utility benefits identified as well as the enabling technology /utility costs associated to achieve the specified benefits.

By understanding the cost-benefit analysis of each Use Case, a California POU will gain perspective on the financial investment aspect deemed necessary to move along the Smart Grid Roadmap defined in Chapter 6 and spark utility movement in further developing a detailed business case for its utility's specific Smart Grid vision and goals.

While some assumptions and costs have been provided, the model requires each utility to provide a number of specific input parameters to most accurately analyze the cost-benefit of each Use Case.

The cost benefit framework is an Excel spreadsheet. Each Use Case's benefits and costs are defined on individual tabs in the workbook:

- Use Case 1: Substation Automation
- Use Case 2: Advanced Metering Infrastructure
- Use Case 3: Distributed Energy Resources
- Use Case 4: Demand Response
- Use Case 5: Distribution
- Use Case 6: Electric Vehicle Charging
- Use Case 7: Asset Management

Each framework is developed from the utility benefit perspective and does not place significant emphasis on the customer benefits. Each Use Case framework includes a section where the benefits are calculated and the costs are defined. Utilities will be required to input utility data into the blue shaded cells of the workbook. This section is to be referenced in conjunction with the business case framework workbook and provides greater insight into the business case utilities will more than likely have to develop to ensure its Smart Grid vision is aligned with and will assist in meeting California's energy policy objectives.

Framework Costs

A detailed business case would include both capital and operating costs; however for the purposes of this framework we will look at only the capital costs associated with the purchase and installation of the Smart Grid technologies and will not be looking at the operating costs associated with the ongoing operations and maintenance of the system(s).

Capital costs typically consist of field equipment (AMI hardware and software, DA/SA equipment), communication infrastructure and back-office IT and control systems; whereas operating costs consist of the labor associated to run the installed systems and ongoing maintenance activities.

It should be noted, costs for the emerging technologies defined in the Use Case and Technology and Implementation Roadmaps are difficult to specify at such a premature (conceptual) stage. A more detailed characterization of the technologies deployed is required before accurate capital (and operating) costs can be estimated with a reasonable degree of certainty. Additionally, this framework does not include utility ongoing operation and maintenance (O&M) costs associated with the Smart Grid technologies deployed.

Specific costs related to each Use Case will be discussed in each Use Case's respective sections below.

Framework Benefits

Smart Grid technologies offer a wide array of utility and consumer benefits, including both operational and customer benefits, including demand response benefits. As previously mentioned, our framework serves as a tool for POUs to begin evaluating Smart Grid and focuses on the utility benefits. An in-depth business case would also include a number of customer benefits. A summary of some of the general benefits of Smart Grid technology are included in Table 19 below.

Specific cost and benefits associated with the Smart Grid Use Cases are discussed in the following sections. For each Use Case, both the quantifiable and non-quantifiable benefits have been identified. Non-quantifiable benefits have been estimated to be either negligible or generally unproven throughout the utility industry.

Table 19: Smart Grid Benefits

Reliability and Power Quality	Smart Grid reduces the cost of interruptions and power quality disturbances. Improvements in reliability are measured by a reduction in the frequency and duration of outages, a reduction in the number of disturbances due to poor power quality, and virtual elimination of widespread blackouts. These benefits can be attributed to the increased ability to monitor the system for disturbances, predict failures and apply "self healing" methods, such as the automated ability to bring DER online during an outage.
	• Reduced operational costs due to fewer truck rolls, and less demand on call center operations, engineering, and outage response resources
	• Improved employee safety as employees are subjected to hazardous conditions less frequently
	• Increased revenues as electricity sales are interrupted less frequently and for shorter durations
	• Higher customer satisfaction ratings and improved relations with the regulator, the community, and so forth.
	• Improved reliability reduces the down time for some generators
Efficiency	Efficiency improvements will reduce the cost of producing, delivering and consuming electricity, thus reducing the O&M and capital investment costs.
	• Increase asset utilization, reduced capital costs as fewer devices fail in service, extended asset life
	• Increased asset data and intelligence enabling advanced control and improved operator understanding, including improved load forecasting enabling more accurate predictions on when new capital investments are needed
	• Reduction in T&D line losses
	• Reduction in transmission congestion costs
	• Reductions in peak load and energy consumption leading to deferral of future capital investments
	• Improved employee productivity through the use of Smart Grid information that improves O&M processes
	• Increased generation efficiency optimization
	• Reduced outages and increased reliability, improved restoration times following storms and other natural events
Economic	The Smart Grid allows direct participation by customer to reduce energy usage and costs, optimizes asset utilization and operational efficiently.
	• New markets created by leveraging DR, microgrids, DER, and others
	• Increased revenues as theft of service is reduced, from improved metering accuracy of smart meters over traditional ones, and shorter power outages
	• Improved cash flow from more efficient management of billing and revenue management processes
Environmental	Environmental improvements result in a reduction in emissions and discharges due to greater renewable integration, improved generator, delivery and consumption efficiencies. Reduced CO_2, NOx, Sox and PM-10 emissions from generating units and losses and reductions in tail pipe emissions can be attributable to AMI, T&D automation and the expected deployment of PHEVs, including vehicle to grid charging (V2G).
	• Renewable integration and storage created by the ability of the Smart Grid to support increased levels of intermittent resources and serve as a buffer for intermittent resources including DER, PHEV/EV and V2G charging
	• Reduction in emissions as a result of more efficient operation, reduced system losses, and energy conservation
	• Reduction in frequency of transformer failures/issues through the use of advanced equipment failure/prevention technologies
Security & Safety	While there have been few reliable reports of cyber attacks on power systems to date, there is an increasing great deal of concern that as the grid becomes smarter and more interactive, disruption of the reliability of U.S. electricity supply will become easier. Smart Grid will reduce the potential of cyber attacks and natural disaster consequences on the grid infrastructure and the number of injuries and loss of life from grid-related events.
	• Reduction in the probability that a deliberate man-made cyber or physical attack could occur and a reduction in the consequences of any that are not detected or prevented
	• Employee safety, fewer accidents

POU Challenges in Developing the Benefits and Costs of Smart Grid

POUs face several challenges with Smart Grid that relate to the cost/benefits of implementing a successful solution.

Developing a robust Smart Grid business case is critical to the successful implementation of any utility Smart Grid program and enables the utility to understand its unique cost/benefit analysis and whether deploying Smart Grid is cost justifiable. Often times it is built on the utility's long term utility vision and serves as a financial investment guide and tracking tool as they move down their Smart Grid maturity roadmap. Surveys of utility decision-makers consistently identify "making the business case" as one of the greatest challenges in developing Smart Grid investment strategies.[36]

POUs are reluctant to move forward in planning for Smart Grid due to uncertainties in how much a true Smart Grid investment will actually cost as well as the hesitation around their ability to build an effective business case for such a new set of emerging technologies and standards and how regulators will respond. No common, publicly available and accepted model is available to assist utilities in applying enterprise-wide Smart Grid cost-benefit analysis making it extremely difficult for utilities to take the initial step in a successful Smart Grid program. Unfortunately, the SGMM does not contain a template for estimating Smart Grid benefits or costs.

The current methods of developing an in-depth Smart Grid business case are too complex for smaller POUs. They require data POUs do not have readily available; data that they do not currently track, collect or report. The POUs will be required to gain a better understanding of what data needs to be collected and how to collect the data to develop a true performance baseline required for the analysis.

Several state and federal-level efforts have been undertaken to provide guidance in evaluating the Smart Grid business case. While these activities provide useful background material, their results fall well short of a detailed "how-to" prescription that would be most useful for individual utility applications. Additional information on some example tools can be found below:

1. EPRI. *Estimating the Costs and Benefits of the Smart Grid A Preliminary Estimate of the Investment Requirements and the Resultant Benefits of a Fully Functioning Smart Grid 2011 Technical Report*. March 2011.
    - http://my.epri.com/portal/server.pt?

2. EPRI. *Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects, Final Report*. January 2010.
    - http://my.epri.com/portal/server.pt?

[36] In this context, making the business case is defined as being able to estimate that forecasted benefits are greater than costs.

3. U.S. DOE. *NETL Smart Grid Implementation Strategy Understanding the Benefits of the Smart Grid v1.0*. June 2010.
   - http://www.netl.doe.gov/smartgrid/referenceshelf/whitepapers/06.18.2010_Understanding%20Smart%20Grid%20Benefits.pdf

4. EDF. *Evaluation Framework for Smart Grid Deployment Plans: A Systematic Approach for Assessing Plans to Benefit Customers and the Environment.* June 2011.
   - http://www.edf.org/sites/default/files/smart-grid-evaluation-framework.pdf

5. Federal Energy Regulatory Commission. *National Action Plan on Demand Response.* Docket No. AD09-10. June 17, 2010.
   - http://www.ferc.gov/legal/staff-reports/06-17-10-demand-response.pdf

6. Pacific Northwest National Laboratory. *The Smart Grid: an Estimation of the Energy and CO2 Benefits*. January 2010.
   - http://www.pnl.gov/main/publications/external/technical_reports/PNNL-19112.pdf

In general, Smart Grid business case analysis is difficult due to the large number of technologies, software, programs and operational practices that cut across all utility operations, require a decade or more to fully implement and most importantly require a vision, plan and roadmap of "where to go" and implementation standards of "how to get there." The end of this section provides general steps necessary in developing a Smart Grid business case model. For reference purposes only, we have provided general guidelines to develop a detailed Smart Grid framework. Also included are the guidelines posted by the CPUC.

The Smart Grid Research Consortium's national survey of electric cooperatives and public utilities conducted in July 2010 found that nearly 90 percent do not apply formal investment models to evaluate Smart Grid options.[37] It is worth noting that over half of the POU survey participants in our study have a well-developed business case model; however, most are AMI centric with emphasis on scalability. ARRA SGIG grant recipients tend to have a more Smart Grid focus model developed that spans beyond AMI to other Smart Grid technologies such as PHEV/EV and SA and DA applications.

Another very important factor when utilities are considering implementing Smart Grid and developing an in-depth business case model is the idea of an incremental versus holistic approach. Fragmenting the business case (for example, looking at the cost/benefits associated with AMI alone without looking at the role AMI can play in enabling DR or providing the communication backbone for DA or SA applications) minimizes your return on investment.

[37] Jackson, Jerry, "Evaluating Smart Grid Investments at US Cooperative and Municipal Utilities" Metering International, Volume 1, 2011, available at http://smartgridresearchconsortium.org/Metering_International.pdf .

Smart Grid investment decisions should not be viewed and evaluated in isolation from related options and applications. Ignoring synergies, and overlooking implementation coordination and timing options can significantly reduce a utilities return on investment. HAN and DR many times are considered to be implemented after AMI and MDMS however, can this approach can significantly reduce returns on AMI system. A well-developed vision and plan should be created prior to developing a Smart Grid business case.

POUs find it difficult to justify the large capital investments required to realize a true Smart Grid and think that it is just "too expensive." Well, how much is too expensive? EPRI now estimates that the cost of Smart Grid for the average residential consumer is $1,033-$1,455.[38] Commercial customer costs are estimated at $7,146 to $10,064 and industrial customer costs are as high as $107,845-$151,877. The Smart Grid city initiative in Boulder, Colorado, has cost Xcel and its partners $100 million, or $2,000 per customer.[39]

California utilities such as SMUD, Glendale and Burbank, are moving forward with large capital investments in Smart Grid only after having completed a rigorous cost benefit analysis. Others, such as City of Banning, City of Colton and ALW are engaging in Smart Grid planning but have made insignificant movement toward Smart Grid implementations due to a number of uncertainties and hesitations, one of the largest attributable to the reasons just stated.

In some cases it is difficult for smaller POUs to socialize the costs across a small customer group where it is more difficult to absorb the cost in its rates.

Many utilities also believe that Smart Grid technology will be cheaper in the future similar to other technology hypes and take a wait and see approach; however, SAIC has noticed over the last several years, the price of the foundational Smart Grid elements such as AMI, DA and substation automation equipment have hit a plateau. This includes IHDs, smart thermostats and load control equipment. Supporting systems such as MDMS and OMS have also come down in cost and have remained constant over the last few years. In addition, such systems as MDMS and OMS have become more scalable for smaller utilities and cooperatives. On the contrary, newer areas such as DMS, energy storage, home energy management systems (HEMs) and other HAN equipment may come down in price over the coming years as these systems become further developed and deployed.

A recent survey conducted by Microsoft Corp. polled 210 utility executives and Smart Grid experts from around the world and only eight percent had passed from planning into implementation phase – which means that 92 percent are taking a much slower approach.[40] Sixty-four percent of Microsoft's survey respondents said they did not have a clear view of the

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[38] *Estimating the Costs and Benefits of the Smart Grid A Preliminary Estimate of the Investment Requirements and the Resultant Benefits of a Fully Functioning Smart Grid 2011 Technical Report*. March 2011.

[39] Ibid.

[40] "Smart Grid Revolution Becomes Disruptive for Utilities Worldwide According to New Microsoft Survey, Micro Soft News Center at http://www.microsoft.com/presspass/press/2010/mar10/03-11SmartGridPR.mspx

enterprise-wide IT infrastructure they will use to structure current and future Smart Grid deployments.[41]

In addition, the capital cost of entry into Smart Grid is a much bigger hurdle for those utilities that serve electric, gas and water services as the benefits to cost ratio may not be as significant. However, AMI for water can introduce significant savings in water meter accuracy and increased revenue.

Economy of scale is another factor hindering the Smart Grid movement of smaller utilities. The costs to deploy the underlying Smart Grid infrastructure such as back-office systems (CIS, GIS, OMS, and MDMS) are less scalable. To gain the same benefit that the large utilities gain, the smaller utilities are required to invest the same amount of capital. Creative Smart Grid solutions will need to be introduced for those smaller POUs that may have hurdles in building a positive business case model. Such creative solutions might entail well developed DR programs including dynamic pricing and in-home devices coupled with EE measures that leverage the Smart Grid infrastructure such as AMI and the HAN. Another creative solution would be to leverage larger surrounding utilities' Smart Grid infrastructure investments. This could include sharing communication infra-structure, head end collection and control systems or back-office IT systems such as MDMS and web portals. A new idea in the industry that could aid smaller POUs in eliminating this up front capital is to utilize a "Smart Grid as a Service" approach where the utility invests in Smart Meters and pays a fee for the infrastructure to support them; thus, minimizing entry capital.

The introduction of knowledgeable Smart Grid staff to run and operate the system (including cyber security positions) is another cost factor that should be considered. This introduces the challenge of determining whether retaining/retraining staff eliminated by AMI and other operational functions is an appropriate approach moving forward.

The benefits of Smart Grid can be extremely difficult to quantify and understand. In fact, some benefits are not even quantifiable today because there is such an uncertainty of whether the implementation of a certain technology or feature will truly benefit the utility. Over the next few years, as more ARRA funded projects report cost and benefit metrics, the industry will become more clear as to the actual realized savings of implementing these technologies and better be able to solidify an approach to calculating these determinants.

The cost of technology obsolescence and interoperability are two other key areas of concern that underlie many utilities' reluctance to deploy Smart Grid technologies right away. Utilities fear technology selections and deployments may become obsolete as further mandates and policies are put into place and technologies continue to change without set standards.

Where Should POUs Invest to Meet CA's Energy Policy Goals?

Understanding what Smart Grid technology provides the biggest impact in meeting CA's energy policy goals is difficult to solidify as each utility is unique.

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[41] Ibid.

Studies published by FERC, DOE and EPRI over the last several years report high benefit to cost ratios for Smart Grid investments. The studies focus on potential savings and costs of AMI and smart meters coupled with customer technologies (such as, IHDs and PCTs) and utility dynamic rate (TOU/CPP) and DR programs and T&D technologies. The reports estimate benefits to be 2.8 to 6.0 times greater than costs.[42] This varies from utility to utility and widely varies between the POUs, Cooperatives, and IOUs; however it represents there are a number of true benefits of Smart Grid and if properly deployed will provide a high return on investment.

The key is identifying and unlocking the values which provide the best return on investment in ways that can be measured by utilities. In this Chapter we will identify a number of benefits for each Use Case to help provide an understanding where benefits can be realized. In order to understand the true potential and priority of investment, utilities should utilize a high level framework, a sample is shown below in which represents the importance of each Use Case in meeting specific long term Smart Grid visions and energy policy goals.

Use Case Benefits

First, utilities should identify the value each technology option has in meeting stated standards/goals. For our sample, the colors represent levels of contribution with red being a low contribution, yellow is a medium contribution and green is high. The contributions are then looked at collectively to determine the significance level of consideration. This initial step helps utilities determine the highest priorities and helps identify top areas to potentially invest. However, other factors should be weighted when determining where to invest. These other factors include where a utility is currently on the Smart Grid maturity roadmap and where they are headed, identified risks such as financial, technology obsolescence and maturity and security should also be weighted.

Recommendations to the Energy Commission for Prioritizing Value and Catalyzing the Cost Benefit Analysis of Smart Grid Technologies among POUs:

- Further investigate and track the costs and benefits associated with the ARRA reported projects to gain a baseline for POUs.
- Develop a standardize framework to help POUs quantify the benefits and costs associated with Smart Grid. This will require a complex modeling approach and should include technology and customer programs such as DR modeled over a 15-year timeframe, at a minimum. It should be capable of modeling multiple Smart Grid applications simultaneously to understand a utilities entire Smart Grid return on investment and cash flow for budgeting and have the capability to quantify the financial implications of alternative strategies and to provide insights on the timing and integration of Smart Grid initiatives across the enterprises.
- Smart Grid investments should be rooted in a business case that identities and quantities the potential for sustainable value delivery, and is informed to the extent possible by experience elsewhere. This prudent approach can be achieved in part through R&D, pilots and demonstration projects, in partnership with the state.

[42] *Ibid. 3.*

Use Case 1: Substation Automation - Integrated Protection and Control Improves Service Reliability

Integrated protection and control using head-end feeder reclosers, relays, and a well developed SCADA system allows utilities to improve the reliability of the protection and control system. Design concepts that eliminate single points of failure for critical protection and control functions reduce the urgency and consequences of failures. A properly designed integration system can leverage the capabilities of the protective relays and other devices to improve operating efficiencies and prevent outages.

Applications which may have greatest potential of both SA and DA are operations and efficiency, including management of peak loads, predictive technologies and communications for equipment, and system restoration technologies.

Benefits of Substation Automation

Reduced Outage Duration: SA can increase reliability and power quality. It reduces the cost of power interruptions by reducing outage duration, SAIDI.

Additional Benefits

There are also a number of other benefits (or those that are harder to quantify) associated with SA, including the following:

- Improve customer satisfaction and minimize economic losses resulting from electrical disruptions
- Improve the stability of the distribution network under inclement weather conditions
- Improve the critical asset life expectancy
- Reduce capital, maintenance and operating expenditures
- Improve abnormal situations detection, systems troubleshooting and preventive maintenance from the use of the information stored in the relay
- Improve engineering analysis and planning using the system currents, voltages and frequency waveforms information
- Decrease the field personnel workload

Cost of Substation Automation

1. Substation Upgrades w/ Upgraded Communications - new infrastructure capable of supporting the higher level of information monitoring, analysis, and control, as well as the communication infrastructure to support full integration of upstream and downstream operations, including the real time data from transmission line sensors, dynamic-thermal circuit ratings, and PMUs to provide real-time monitoring of equipment and reliability centered predictive maintenance. Historically, the EMS or SCADA system communication system was used; however increased latency and bandwidth is required. It is estimated $50,000-$75,000 per substation to achieve the optimal performance level of communication for Smart Grid.
2. Distribution Management System (DMS) - $150/customer (Optional)
3. Intelligent head-end feeder reclosers and relays -$50,000/feeder

Table 20: Substation Automation Costs and Assumptions[43]

DMS	$	150/customer
Intelligent head-end feeder reclosers and relays	$	50,000/feeder
Communications to feeders for AMI and distribution smart circuits	$	20,000/feeder

Use Case 2: Advanced Metering Infrastructure - Smart Meters Enhance Utility-Customer Interaction

Increasing utility and customer interactions can provide significant value to both the utility and consumer. AMI is one of the predominant applications being considered to enhance this link. AMI provides a number of benefits, most notably, the operational and customer service benefits.

Benefit to Cost Ratio of AMI

A study conducted by the Brattle Group and EEI in early 2011 concluded that utilities studied in the west (approximately 1 million meters) have the lowest operational benefits among other utilities located in the south, central and east regions. The overall benefit to cost ratio for smart meters in the West is 1.5 which includes the addition of customer options/programs, as shown below in Figure 14.

[43] *Ibid*. 3.

Figure 14: Benefit to Cost Ratio of AMI[44]

Total NPV Costs, Benefits, and Net Benefits (2011 - 2030)

Value streams	Total Cost	Total Benefit	Net Benefit
AMI installation	187,721,976		-187,721,976
AMI avoided metering		59,891,650	59,891,650
AMI value of outage avoidance		19,759,280	19,759,280
AMI remote connect/disconnect		1,257,725	1,257,725
Web portal		0	0
IHD	0	0	0
DLC with M&V		60,737,609	60,737,609
PTR		54,598,358	54,598,358
PTR with enhanced PCT	27,714,414	78,998,937	51,284,523
CPP		11,568,973	11,568,973
CPP with enhanced PCT	23,364,084	63,333,472	39,969,389
EV	32,679,492	62,545,025	29,865,533
Total	**271,479,966**	**412,691,030**	**141,211,064**

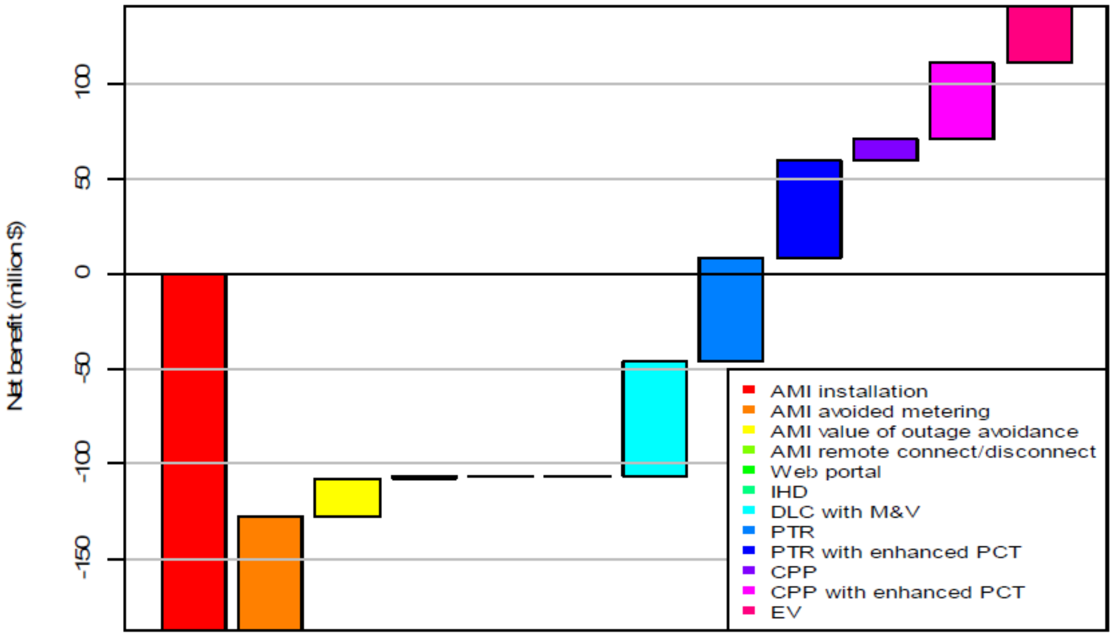
Operational gap	**106,813,321**
Operational gap, percent	**57%**

Benefit cost ratio	**1.5202**

Utilities in the West had the largest operational gap among other regions due to the increased amount of AMR already in place, indicating that utilities had captured the "low hanging fruit" of operational benefits. It also showed that DR helped close the gap between the AMI costs and benefits. Figure 15 represents the net benefits of AMI in the west.

[44] Institute for Electric Efficiency and The Brattle Group. IEE Releases: The Benefits of Smart Meters, NARUC Winter Meetings, February 16, 2011.

Figure 15: Net Benefits of AMI[45]



Also, by integrating information from the AMI system with other DA applications, utilities can leverage the investment of AMI to provide additional value by dispatching DR for local load relief when needed for local system control.

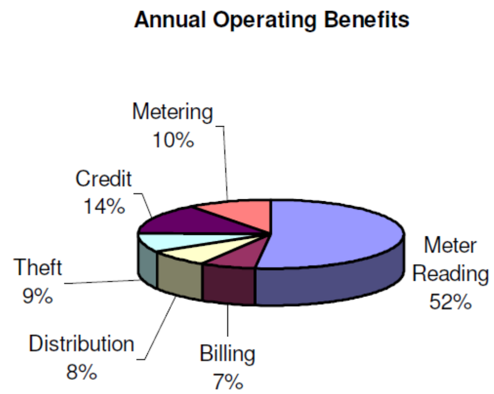
Benefits of AMI

AMI provides a number of operational, financial, environmental and customer benefits. For a utility without AMR, the operational benefits typically account for more than 70 percent of the cost of the investment. Utilities that include DR can increase their benefit to cost ratio substantially.

Figure 16 represents SMUD's operational benefits, which excludes any DR benefits. About 77 percent of the AMI benefits identified by SMUD are in 3 areas: Meter Reading, Credit and Collection, and Metering; areas where there is a very high probability of achieving the benefit. This is generally consistent with most utilities that do not already have AMR in place. The SMUD business case returned a result of 8.6-20 percent IRR with a NPV between $16-61 million.

[45] Institute for Electric Efficiency and the Brattle Group. IEE Releases: The Benefits of Smart Meters, NARUC Winter Meetings, February 16, 2011.

Figure 16: SMUD's Operational Benefits of AMI



Increase Operational Efficiencies

Reduced Meter Reading: AMI eliminates the need to send meter reading personnel to manually read meters, reducing meter reading labor. This benefit includes the labor savings associated with scheduled and un-scheduled meter reads, remote disconnects/reconnects associated with move-in/move-outs and credit and collections.

Improved Reliability and Power Quality: AMI can instantly detect power quality issues and loss of power, enabling system operators to rapidly diagnose system problems and more rapidly restore service. Meter communications can improve outage management, reduce outage costs and avoid crew dispatch to "no power" call locations. Figure 17 represents the average electric customer interruption costs by duration and type that were used in the Use Case framework.

Figure 17: Average Interruption Cost by Duration and Customer Type[46]

Interruption Cost	Interruption Duration				
	Momentary	30 minutes	1 hour	4 hours	8 hours
Medium and Large C&I					
Cost Per Event	$6,558	$9,217	$12,487	$42,506	$69,284
Cost Per Average kW	$8.0	$11.3	$15.3	$52.1	$85.0
Cost Per Un-served kWh	$96.5	$22.6	$15.3	$13.0	$10.6
Cost Per Annual kWh	9.18E-04	1.29E-03	1.75E-03	5.95E-03	9.70E-03
Small C&I					
Cost Per Event	$293	$435	$619	$2,623	$5,195
Cost Per Average kW	$133.7	$198.1	$282.0	$1,195.8	$2,368.6
Cost Per Un-served kWh	$1,604.1	$396.3	$282.0	$298.9	$296.1
Cost Per Annual kWh	1.53E-02	2.26E-02	3.22E-02	$0.137	$0.270
Residential					
Cost Per Event	$2.1	$2.7	$3.3	$7.4	$10.6
Cost Per Average kW	$1.4	$1.8	$2.2	$4.9	$6.9
Cost Per Un-served kWh	$16.8	$3.5	$2.2	$1.2	$0.9
Cost Per Annual kWh	1.60E-04	2.01E-04	2.46E-04	5.58E-04	7.92E-04

TOU/CPP and HAN: Dynamic rates such as TOU and CPP encourage consumers to reduce energy usage and peak demand. It is estimated there is a 13 percent reduction in peak load for consumers on TOU/CPP rates. This number increases to up to 20-30 percent with TOU/CPP and an in-home device where consumers are able to see their energy usage and the price signal. Even a 3 percent reduction in peak load can be realized by visually representing to customers their energy usage via an IHD or Web Portal application.

Support Customer HAN and Smart Appliances: Increased knowledge of energy usage via online web portal applications and in-home devices such as IHDs, smart thermostats and load control devices. New dynamic rate options can also provide customer choice. It should be noted however, to realize the full AMI system potential, internal utility billing and customer applications may need to be modified to make use of AMI capabilities, such as new dynamic rates.

Distributed Energy Resource Integration (PV, Wind, PHEVs): AMI provides net metering capabilities to enable the integration of DERs and can also be integrated to demand management systems, EMS system or DA applications to automate DERs.

[46] Source: Sullivan, M.M., Mercurio, M., Schellenberg, J. (2009) "Estimated Value of Service Reliability for Electric Utility Customers in the United States," Report LBNL-2132E, prepared for the Office of Electricity Delivery and Energy Reliability, U.S. Department of Energy, Berkeley, CA: Lawrence Berkeley National Laboratory, p. xxvi, Table ES-5, June 2009.

Financial Benefits

AMI provides for increase utility revenue due to decreased theft, increase accuracy of the smart meters and the ability of AMI to provide a reduced "read to bill" window reducing revenue float.

Decreased Theft: Smart meters can typically detect tampering. MDMS systems can analyze customer usage to identify patterns that could indicate diversion. It has been shown that with AMI utilities can save on average between 0.5-1 percent of electricity due to the identification of theft related events. For our framework, we've used a conservative estimate of 0.5 percent of total electricity sale kWhs.

Lower Read to Bill Window: AMI also provides for a shorter read to bill window. AMI can provide a read to bill time period of 1 day, which most utilities today (without AMI) typically use a 5-10 or more day window. This feature of AMI allows the utility to gain revenue faster and gain the cost of money associated with those revenues. We have used a conservative estimate in our framework of a two day read to bill window with the implementation of AMI.

Increased Meter Accuracy: Smart meters also offer increased accuracy from electromechanical meters. It has been shown, that switching from Non–AMR electromechanical meters to smart meters improves the accuracy by 0.5 percent. Additionally, switching from AMR meters to AMI smart meters can lend itself to an increased accuracy of 0.3 percent.

Asset Optimization, Reduced Equipment Failures, and Optimized Generator Operations: Asset utilization and capital deferral are terms used when determining the need for additional capital plant. Asset utilization measures the total system production versus the system's full capacity. At the point assets become fully utilized additional plant and capital outlay is required. Deferring these costs, through asset utilization, general provides significant cost savings. An organizations ability to effectively manage their assets depends greatly upon the quality and amount of information available. An AMI system provides vast improvements over what has been traditional available. We have not provided a benefit calculation in the Use Case framework as this is dependent from utility to utility.

Operations and Maintenance Improvements: Installing all new meters (or upgrading and testing existing meters during retrofit) can postpone the normal meter maintenance cycle. We have not provided a benefit calculation in the Use Case framework for this benefit as it varies greatly from utility to utility.

Reduced Call Center Operations Labor: AMI can provide between 5 and 15 percent reduction in labor associated with the calls from customers. AMI eliminates misreads, delayed bills, high bill inquiries due to inaccurate reads, re-bills and provides customer service representatives with enhanced energy usage information to accurately and quickly answer customer questions. We have assumed a 5 percent reduction in call center labor, which we feel is a conservative estimate.

Customer Benefits

Increased Customer Service Offerings: AMI enables utilities to provide increased accuracy on customer bills due to the elimination of estimated reads and error meter reads. AMI also enables CRS to provide more in depth information and faster response times on customer inquiries.

Reduced Outage: AMI provides for faster outage detection and therefore, less disruption to a customer's home or business.

Greater Control of Energy Consumption: Smart Meters enable a utility to measure a customer's electricity usage in 15 minute or hourly increments. That coupled with dynamic rates and in home devices or web portal applications options allow customers to better manage energy consumption and potentially lower their electricity demand during peak periods and save money.

Increases Privacy: Usage information is relayed automatically to the utility for billing purposes without on-site visits by a utility.

Reduced Emissions: Because AMI provides remote meter reads, fewer miles will be driven reducing emissions (CO2, S0x, N0x and PM). Additionally, lowering energy usage, peak demand and energy losses also contribute to lower emissions. We have not provided a calculated benefit in the Use Case framework for emissions reduction savings related to AMI.

Additional Benefits

There are also a number of less quantifiable benefits (or those that are harder to quantify) associated with the implementation of AMI, including the following:

- Reduced distribution losses
- Deferred T&D and Generation and Capacity Investments
- Reduced Congestion
- Reduced Ancillary Service Costs
- Elimination of exception billing due to bad meter reads or bad estimated reads
- Increased Security
- Reduced Oil Usage
- Reduced Wide-Scale Blackouts
- Reduced Employee and Vehicle Accidents/Increased Safety

Cost of AMI

The total capital costs of deploying AMI includes hardware and software costs (smart meters, the AMI communication/network infrastructure and head end management software) as well as installation costs, project management, meter data management and information technology integration costs. Figure 18 shows the typical breakdown of AMI system costs.

Figure 18: Cost Breakout of AMI

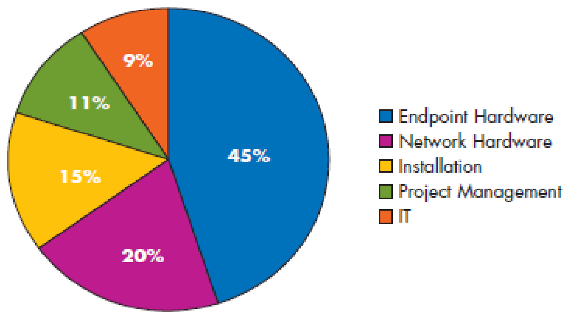


Table 21 represents the costs associated with AMI used in the framework.

Table 21: AMI Costs and Assumptions[47]

Total Combined Installation/Equipment for AMI	$ 212/customer
MDMS (optional)	$ 8/customer
OMS (optional)	$ 8/customer
IHD /DLC Device	$ 100 /customer
Medium Utility Cyber Security Costs	$ 400k/year $40k ongoing

Use Case 3: Distributed Energy Resources - Integrated Distributed Generation & Storage Supports Grid

As demand response is the management of system outputs, the facilitation of distributed generation is the management of system inputs.

Deploying DER technologies and capabilities will defer T&D system improvements, traditional generation, and reduce losses. This is assuming a low level of controlled DER by the utility (if strict controls were implemented, it would more than likely not cost justifiable). We assume utility control is limited to only AMI being installed and AMI supports net metering (at no cost). We are also assuming the distribution system can handle the new DER without improvement (or improvement is paid for by the customer).

[47] *Ibid*. 3.

Demand-side participation is essential for California to:

- Integrate renewable energy
- Meet greenhouse gas reduction targets
- Increase energy efficiency
- Support electric vehicles
- Realize full benefits of the Smart Grid
- Optimize distribution and transmission grid capacity

California will only get the full benefits of renewable energy if consumers can react to signals when renewable power is most available. That's because energy efficiency is not just about lowering peak demand, but also about balancing demand and supply.

Benefits of Distributed Energy Resources

DG facilities offer potential advantages for improving the transmission of power by producing power locally for users, which aids in the entire grid by reducing peak demand and by minimizing congestion. By building localized power generation facilities rather than power plants located distantly from load centers, DG can contribute to deferring transmission upgrades and expansions, as investment in such facilities remains constrained. DG technologies can also improve the security of the grid. Decentralized power generation helps reduce the terrorist targets that nuclear facilities and natural gas refineries offer, and, in the event of an attack, better insulate the grid from failure if a large power plant goes down.

Avoided T&D Losses: Distributed resources can improve the efficiency of providing electric power. By managing peak feeder loads with DG, peak feeder losses, which are higher than at non-peak times, would be reduced. Industry average indicates electricity losses from a power plant to a typical user is roughly between 4.2 to 8.9 percent of the electricity as a consequence of aging transmission equipment, inconsistent enforcement of reliability guidelines, and growing congestion. For the purposes of this framework, we have assumed system losses are 7 percent.

Reduced Outages and Improved Reliability: The benefit to consumers is based on the value of service (VOS). Distributed generation could be used as a backup power supply for one or more customers until normal electric service could be restored. If used as part of the recovery of the system, then its value is already accounted for, and it can be counted as an individual customer benefits. By using a utilities SAIDI hours and an estimated reduction in outage hours of 5 percent due to DG, the total number of customers with installed DG and the cost of energy, a utility can calculate the total outage hours reduced due to DG and the savings associated with those reduced outage hours by multiplying it by the cost of energy.

Increased Power Quality: DER also improves power quality—variations in voltage or electrical flow—that results from a variety of factors, including poor switching operations in the network, voltage dips, interruptions, transients, and network disturbances from loads. The use of on-site power equipment can conceivably provide consumers with affordable power at a higher level of quality. In addition, residents and businesses that generate power locally have the potential to sell surplus power to the grid, which can yield significant income during times of peak demand. Beyond efficiency, DG technologies may provide benefits in the form of more reliable power for industries that require uninterrupted service.

Reduced Ancillary Services Cost: The reserve margin is a required capacity above the peak demand that must be available and is typically on the order of 12-15 percent of peak demand. If peak demand is reduced, reserve margin can be reduce, which requires that the peak be permanently reduced. EPRI estimates ancillary service cost can be reduced due to the integration of DG, equal to 3 percent of the wholesale energy cost on average for a utility. Multiplying the total wholesale energy cost by 3 percent provides the estimated savings associated with reduced ancillary service costs.

Avoided T&D Infrastructure Capital: DG can be used to relieve load on overloaded feeders, potentially extending the time before upgrades or additions are required. Utilities typically build transmission with capacity sufficient to serve the maximum amount of load that planning forecasts indicate; however, this is only required for very short periods each year during peak demands. Providing generation capacity closer to the load reduces the power flow on transmission lines, potentially avoiding or deferring capacity upgrades. We have assumed the price of generation capacity at annual peak per MW is equal to $50 according to EPRI. Multiplying this by the DG annual peak in MW provides you the total that could potentially be saved due to installed DG.

Reduced Emissions: Renewable-based DG can provide energy with greatly reduced net CO_2 emissions produced by fossil-based electricity generators. DG technologies minimize the emissions produced by large, centralized power plants, including carbon monoxide, sulfur oxides, particulate matter, hydrocarbons, and nitrogen oxides. However, depending on the type of DG and the central generation mix during peak and off-peak times, the impact can be positive or negative.

Additional Benefits

There are also a number of unquantifiable benefits (or those that are harder to easily quantify) associated with the implementation of DG and Energy Storage, including the following:

- Reduced Congestion: DG provides energy closer to the end use, so less electricity must be passed through the T&D lines, which reduces congestion.
- Reduced Peak Demand
- Higher load factors
- Increased transmission and distribution capacity: Utilities build transmission with capacity sufficient to serve the maximum amount of load that planning forecasts indicate. The trouble is, this capacity is only required for very short periods each year, when demand peaks. Providing generation capacity closer to the load reduces the power flow on transmission lines, potentially avoiding or deferring capacity upgrades. This may be particularly effective during peak load periods.

- Help increase diversity of energy sources which helps insulate the economy from price shocks, interruptions, and fuel shortages.
- Displaced fuels

Cost of DER

1. AMI and DMS: Benefits attributable to DG and Energy Storage can be attained with the implementation of AMI alone. Utilities can begin installing DG on its grid network and implement upgrades to accommodate the sparsely installed DG; however, as regulatory mandates press for greater installation and larger amounts are installed, a higher level of control will be necessary and utilities may need to pursue a DMS to manage the resources. For our analysis we have assumed the costs to include that of AMI at $212 customer and have provided an optional cost for DMS at $150/customer. It is assumed that customers will fund the purchase of their own DG sources. We are assuming in our cost estimates the utility system is capable of supporting DER and energy storage applications. Additionally, the cost estimate of AMI assumes no control is required, just monitoring and bill payment/settlement is provided by the AMI system along with net metering capabilities.
2. SCADA will be required to be in place and is estimated at $170/customer. A low latency communication network is required.
3. An EMS will likely be required to meet California's 2020 Smart Grid vision and policy goals. An EMS has an estimated cost of $50,000 per feeder. Some utilities may choose to deploy a DMS or Energy Demand Management System in lieu of an EMS and such costs should be accounted for herein. The utility will also require a network model to be in place. This is estimated at $2 per customer.
4. Solar PV systems also require an Inverter which costs $900 per inverter.
5. Costs for energy storage devices have not been provided and it is assumed the customers fund the DER.

Table 22: ER Costs and Assumptions

SCADA	$ 170/Customer
Energy Management System (required to meet 2020 goals)	$ 50,000/feeder
DMS (Optional)	$ 150/customer
AMI meters (at DER locations)	$ 212/customer
Network Model	$ 2/customer
Integrated PV Inverter	$ 900/inverter

Use Case 4: Demand Response - Active Load Management Reduces Peak Demand

Higher penetrations of DR will be an important resource in California as peak loads continue to increase. Utility DR programs reduce peak demand by active load management during times of high wholesale energy prices or system emergencies and reduce consumption by changing the price of electricity for consumers which basically induces a load response when contingencies and market imbalances exist. DR can be applied to address the entire system, in a planning area, at a substation, and a feeder. There are a number of DR programs and applications. Development and incorporation of DR, demand-side resources, energy-efficiency resources and resources to monitor and control them continue to rise and will assist California's POUs in meeting energy policy goals.

Smart Grid technologies such as AMI, provide a two-way communication capability of near-real-time price signals that are linked to wholesale prices to consumers and can send and receive messages from direct load control or in home DR devices such as smart thermostats. Such information will create the incentive for consumers to respond to prices just as they do for most other products they purchase. This response is tied to the main benefit of DR which is peak demand reduction for increased reliability.

Hourly load forecasts and impact of direct load control, pricing programs, customer engagement and in-premise technologies and programs such as programmable communicating thermostats and critical peak pricing programs are important contributors to calculating overall Smart Grid benefits.

Because the Commission policy is to follow the loading order and focus on the long-term development of clean energy resources and reduced greenhouse gas emissions, some consistency in DR and incentive programs will be necessary to attract and retain DR participants and should be a valid consideration in designing programs to reflect DR's position in the loading order.

California's DR Potential

In 2008, FERC estimated 4.7 percent of the U.S. customers had advanced meters, and that 8 percent of U.S. customers were engaged in some form of DR program.

There are a number of DR programs including incentive based DR programs and dynamic pricing programs. According to FERC's 2010 Assessment of Demand Response and Advanced Metering, California has a potential for the following potential peak load reductions by DR program type:

Table 23: California Potential for Peak Load Reductions due to DR

DR Program Type	MW Reduction
Time Based Rates	534
DLC	785
Other Incentive Based	593
Emergency DR	425
Interruptible Load	457
Other	1
Total for CA	**2,795**

Dynamic Pricing with Enabling Technology

A CPP experiment in California in 2004 determined that residential and small commercial customers are price responsive and will produce significant reductions in peak loads. Participants reduced load 13 percent on average, and as much as 27 percent, when price signals were coupled with automated controls such as controllable Programmable Communicating Thermostats (PCTs). The reduction was greater for customers in the warmer climate zones, and even larger for those with central air conditioning. Customers equipped with enabling technologies (automatic price-sensitive thermostats) delivered a response that was twice as high as those customers who did not have enabling technology.

By sending better price signals to consumers through dynamic pricing programs, the price elasticity of demand increases, which decreases the degree to which market power can be exercised, which is often a major concern.

During California's Statewide Pricing Pilot, it was determined that:

- Peak-period impacts on critical days were 50 percent higher for residential customers with air conditioning and PCTs than for AC households with no PCTs
- For C&I customers with demands less than 20 kW, there was no reduction on critical days without PCTs but a 13 percent reduction with PCTs
- For C&I customers with demands between 20 and 200 kW, there was a 5 percent reduction without PCTs and a 10 percent reduction with PCTs

California is one of the few states that have adopted a CPP tariff as its default rate for commercial and industrial customers.

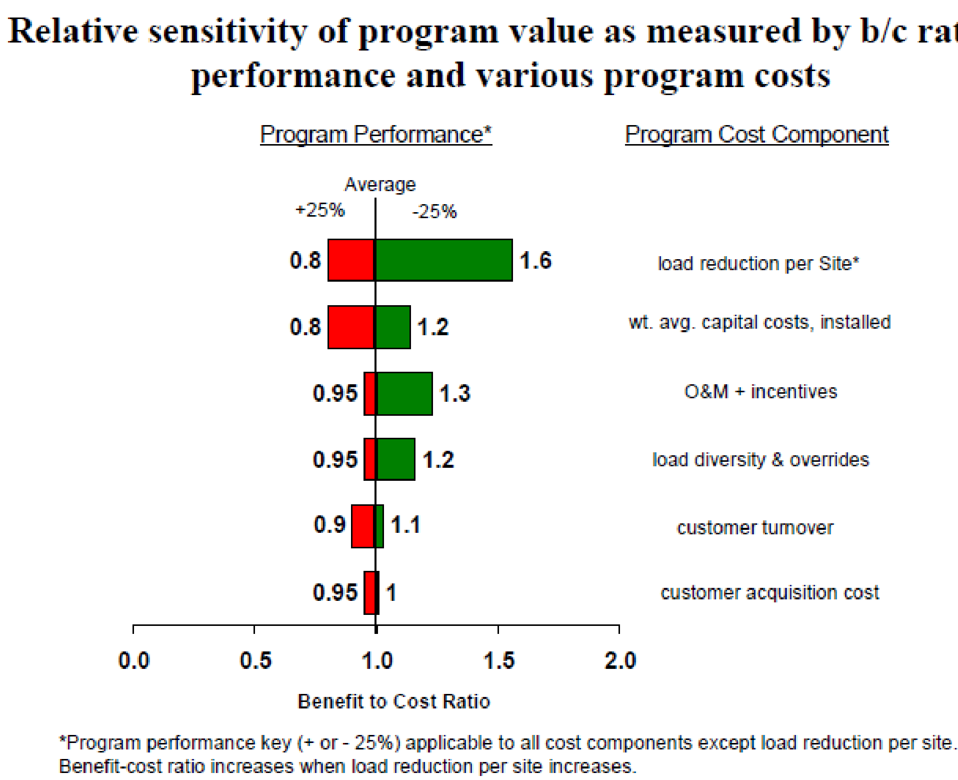
Benefit to Cost Ratio of Demand Response

DR program economics are most sensitive to the amount of load curtailed per site and upfront technology costs as shown in Figure 19[48]. Program incentive payments, O&M costs, percent of

[48] http://www.swenergy.org/publications/documents/Demand_Response_White_Paper.pdf

customers who drop out of the program, and overrides also matter to the degree that they impact the amount of curtailed load per site. Other factors, such as customer acquisition costs and program administration, play a small to negligible role in determining program cost effectiveness. It should be noted that studies reporting benefit-cost ratios of DR programs are few and evaluation methodologies and DR reporting methods are inconsistent for results are mixed, thus making it difficult to compare from utility to utility.

Figure 19: DR Program Benefit to Cost Ratio[49]



Coupling of Demand Response and Energy Efficiency Benefits

Many times utilities operate EE and DR programs independently of one another, however they are not mutually exclusive. Efficiency and demand response fulfill different but complementary goals for utilities trying to serve customers cost effectively, while complying with energy policy.

DR is a short term solution. It lowers peak power requirements and helps create price elasticity. It relieves generation capacity and transmission capacity during a peak demand period. EE is a

[49] *Source: RMI. Demand Response: An Introduction, April 30, 2006.*

long term solution whereby it reduces overall system load, lowering energy costs for customers. Lower energy means less generation required and resulting emissions.

Utilities should couple DR with EE programs as part of a demand-side resource package to leverage the different strengths of each and to flatten the utility's system load curve.

Benefits of Demand Response

The avoided costs of supplying electricity are a primary benefit of any demand side resource. System benefits of DR include deferred or eliminated generation capacity expansion, deferred or eliminated transmission/distribution capacity expansion, and reduced plant-operating costs or more specifically shifting of consumption away from peak hours to lower cost energy supply periods. The benefits of DR applications can also include reduced line losses, emissions, ancillary services costs, and renewable energy purchases. Net energy savings from DR are small compared to the amount of load reduced or shifted, particularly in load-response programs.

Reduced need for Generation Capacity: The most significant avoided cost is the avoided cost of generation capacity. Load that is reduced during times when the power system has encountered critical conditions (in the form of higher prices on wholesale markets or in the form of stress from supply insufficiency) will carry greater value than load that is reduced during normal times. Because many power plants that serve peak demand have very low utilization factors, on the order of only 100 hours out of the year (or one or two percent of the total hours in the year), avoiding the cost of building a new peaking capacity can result in significant savings.

Because generating units can breakdown and peak demand is inherently uncertain, electric power systems must have a reserve margin (more capacity than needed on peak to accommodate unforeseen outages). Typically, a 12–15 percent reserve margin is employed to ensure reliability. As a result, every megawatt of peak consumption reduced by DR results in the savings of not just one megawatt of avoided peak capacity costs, but also the avoided reserve margin. So, if the target reserve margin is 15 percent, one MW of avoided peak consumption results in 1.15 MW of avoided peak capacity investment.

The California PUC provided an estimate of $85/kW-yr, representing the avoided cost of a peaking generation unit. PG&E elected to use a more conservative estimate of $52/kW-yr. We have assumed a $50/kW-yr in our framework.

Reduced T&D Capacity: DR enables utilities to defer T&D capacity investments due to reduced energy demand. The 2012 monthly T&D capacity values, by utility, are shown in Table 24 for PG&E, SCE and SDG&E. For our analysis, we have assumed $10/kW-Yr.

Table 24: 2012 T&D Avoided Cost Values

Utility	Transmission	Distribution
PG&E	$19.58	$57.03
SCE	$23.85	$30.71
SDG&E	$21.50	$53.28

Avoided Energy Purchase Cost: Utilities avoid the purchase of energy by directly controlling customer loads during peak periods. Our framework assumes a cost of peak energy of $90 per MWh.

Avoided Ancillary Services (AS) Costs: Reduced load resulting from a DR event could reduce the quantity of AS procured in the Real-Time market. However, as 85 percent or more of AS is procured by the CAISO in the Day Ahead market, and AS costs are a relatively small percentage of the overall DR benefits, the benefit of reduced AS procurement due to DER are negligible. DR programs however can earn revenue in the AS and other CAISO markets.

Increased Reliability: DR provides operational reduces the likelihood and consequences of forced outages that impose financial costs and inconvenience on customers including wide scale blackouts. DR also reduces dependency on oil.

CAISO Market Participation Revenue Benefit: CAISO allows DR to participate directly in ancillary services (AS) and other markets and can be a benefit for some utilities through dire participation with CAISO. We have not included this benefit in our framework.

Environmental Benefits: By decreasing generation, you reduce emissions. We have provided a benefit calculation for the reduction of CO2 in the framework. We have assumed a $50/ton of carbon cost[50].

Avoided Renewable Energy Purchase Procurement Costs: A small benefit of DR compared to the overall benefits of DR programs is the avoided renewable energy purchases procurement costs.

Customer Benefits: Customer benefits include bill reductions due to less energy usage or from shifting usage to lower-priced hours, Incentives paid, participant non-monetary and non-energy benefits and tax credits, if available.

Dynamic Rates: Dynamic rates such as TOU/CPP rates with enabling technologies have been discussed in Use Case 2.

Lower Wholesale and Retail Prices: The Electric Power Research Institute concluded that a 2.5 percent reduction in electricity demand statewide could reduce wholesale spot prices in California by as much as 24 percent.

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[50] DOE. The Smart Grid: An Estimation of the Energy and CO2 Benefits, January 2010.

Costs of DR

As previously shown, the cost to implement DR is much less than the value obtained. Individual DLC device (not integrated with AMI) such as a PCT are estimated to cost $100 per device. Installation of those devices can be up to $50 per device. DR can leverage an AMI system for send/receive of message to the endpoint devices, aggregation and display of interval usage information and serve as a Demand Response Management System. AMI can be estimated at $212 per customer and a DRMS is estimated at $100 per customer in the event DR is deployed without AMI. Some more advanced households that deploy many DR and DER resources may require a HEM which is estimated to cost $225 per customer. A simple IHD used with an AMI system or some other DRMS system can be purchased for $100 per device.

Table 25: DR Costs and Assumptions

Direct Load Control Device (not integrated with AMI)	$	100
DLC Installation	$	50
Demand Response Management System (if AMI is not used)	$	100
AMI	$	212
HEM	$	225
IHD	$	$100

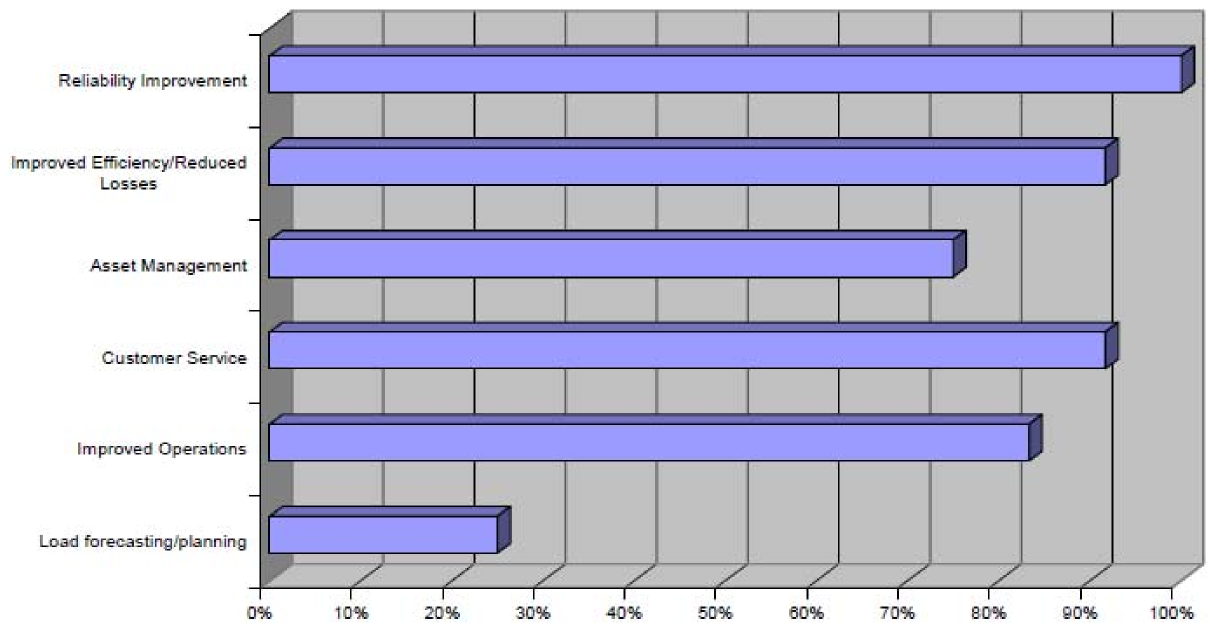
Recommendations to the Commission for DR:

- Coordinate state and local education efforts should be undertaken to make consumers aware of DR initiatives, AMI and dynamic pricing.
- Generate a common information platform on program design, implementation and evaluation of determined best practices.
- Define standards for evaluating, measuring and verifying energy savings and peak demand reduction.
- Clearly articulate the expected role of DR to allow utilities to plan for and include DR in operational and long-term planning, and recover DR costs.
- Develop a functional specification framework for DR programs.

Use Case 5: Distribution Automation - Voltage Management Improves Power Quality and Delivery Efficiency

DA involves the integration of SCADA systems, advanced distribution sensors, advanced IED's and advanced two-way communication systems to optimize system performance. Figure 20 represents the categorical benefits used to justifying the technology, with increased reliability, customer service, and increased efficiency and reduced losses coming in on top.

Figure 20: Categorical Benefits used to Justify DA and SA Technology[51]



Benefits of Distribution Automation

There are a number of DA applications available today. Top applications include increasing operational efficiency (Volt/VAR, switched capacitors, voltage regulators, advanced sensors), management of peak loads, prediction of equipment failure and system restoration after a failure.

Integrated Voltage Management

Voltage/VAR controls are a basic requirement for all electric distribution feeders to maintain acceptable voltage at all points along the feeder and to maintain a high power factor. The basic principal of all voltage management is to reduce the voltage level from that of the incoming supply. Recent efforts by distribution utilities to improve efficiency, reduce energy and demand, operation and maintenance cost, and achieve better asset utilization, have indicated the importance of voltage/VAR control and optimization.

[51] California Energy Commission:. Value of Distribution Automation Applications, April 2007.

Integrated Voltage Management continuously analyzes and controls such equipment as load tap changers (LTCs), capacitor banks, and voltage regulators to manage system power factor and voltage. This allows utilities to flatten each feeder's voltage profile and to lower average voltages, resulting in significant energy savings while simultaneously maintaining unity power factor to eliminate technical losses.

Reduced Energy due to Conservation Voltage Reduction (CVR): CVR has been shown to reduce load by 0.7 percent by reducing voltage by an average of 1 percent (Assuming rates are still able to recover all utility costs, decoupled from kWh sales). Implementing CVR is good when wholesale power costs are based on coincident peak demand costs, there is a need to supplement an existing load control program, or there is a need to minimize interruptions, assist with overload management and reliability improvements. Some studies indicate that energy would be reduced by 1.5 percent for every 3 percent reduction in voltage.

Reduced Peak Demand (CVR): A savings associated with peak demand can also be attributable to CVR by assuming a reduction of voltage by 5 percent with a yield of 0.656 percent in demand reduction per percent voltage drop. This benefit is calculated using the cost of wholesale power, daily peak load and the number of peak coincident events.

Automated Feeder Management

Smart Grid will enable a self-healing distribution system. Automated feeder management improves service reliability by reducing outage times and restoring service through isolation, rerouting and prevention. Also, Automated Feeder Management reduces ongoing distribution O&M costs as well as reduces restoration costs.

Reliability - Shorter Outages Duration due to Automated Switching: The primary benefit stream from automated switching for isolating faults during a contingency is reliability. This application does not reduce the number of momentary outage occurrences but can greatly reduce the duration of those outages for large groups of customers and possibly reduce the duration below the 5 minute SAIDI threshold. As such, this value depends on the number of reduced outage hours it can provide.

Power Quality: A reduction in harmonic distortion, fewer and less severe voltage sags and surges, causes less damage to customer-owned equipment and lost production.

O&M Savings Related to Automated Switching: Automated switching reduces the manual labor associated with field personnel. Utility cost savings from the automated switching technology accrue as reduced labor and transportation costs. Reduced costs from utility staff not having to travel to switching sites to manually operate switches.

Additional Benefits

DA may provide a utility all or some of the following benefits depending on the exact equipment and monitoring/control systems are deployed.

- Global and regional views of available and unavailable VARs
- Improves System Reliability and stability of the distribution network under transient conditions (resulting from fault and switching operations).
- Improves feeder voltage profile
- Extended Asset Life and Associated O&M and Capital associated with failed equipment due to faults
- Automatic Islanding and Resynchronization could be applied to provide value for loads within the microgrid, and also for utilities to enhance operating flexibility in portions of the system.
- Reduces line losses
- Releases system capacity
- Defers construction costs
- Eliminates PF Penalties
- Adapts to system reconfiguration
- Notification of equipment malfunction
- Reduced emissions

Costs of Distribution Automation

The cost for distribution infrastructure enhancements including advanced relays, voltage/current sensors and regulators, recloser controls, capacitor banks, LTCs, RTUs, IEDs, PLCs, FCIs, automated switches and controllers is estimated at $170 per customer. The per customer cost is derived from EPRI's estimate of $308,000/feeder with an average of 1,800 customers per feeder. EPRI based this cost on actual utility estimates in 2009. EPRI also estimated that CVR costs on average $258,000/feeder. The DMS cost is based on utility client business case models and proposals received from various DMS vendors. The stated AMI costs were derived from EEI and the Brattle Groups February 2011 Report on the Benefits of Smart Meters and are in line with other utility client investments.

Table 26: Distribution Automation Costs and Assumptions

Distribution Infrastructure Enhancements (Advanced relays, voltage/current sensors and regulators, recloser controls, capacitor banks, LTCs, RTUs, IEDs, PLCs, FCIs) automated switches and controllers. This per customer cost is made up of the following:	$ 170/Customer
• Intelligent head-end feeder reclosers and relays	$ 50,000/feeder
• Intelligent reclosers	$ 125,000/feeder
• Remotely controlled switches	$ 60,000/feeder
• Power electronics, including distribution short circuit current limiters	$ 80,000/package
Voltage and VAR control on feeders	$ 258,000/feeder
DMS with Network Model (Optional)	$ 150/customer
AMI (Optional)	$ 212/customer

Smart Grid software will be able to combine information flowing from the automated substations with SCADA data points throughout the distribution system to analyze and recommend re-configuration of the distribution system for optimum performance. Circuit optimization will minimize line loses and integrate customer data from AMI to regulate voltage while still maintaining acceptable levels for customers. This functionality will help support CVR strategies to achieve energy savings.

Recommendation to the Commission for DA:

- Further work associating the value of DA relative to state and federal energy policy goals such as the integration of renewable distributed generation, prioritization of energy efficiency, and reduction of greenhouse gasses in electricity generation, will be beneficial in making DA technologies more widely deployed in the most suitable applications.

Use Case 6: Electric Vehicle Charging - Grid Monitoring and Control Enables Wide-scale Electric Vehicle Charging

Several car manufacturers have already commercially produced PHEVs/PEVs in California. With this, charging stations also referred to electric vehicle service equipment "EVSE" for both residential and C&I are being offered. The charging stations are currently being offered in single phase at 110 and 240 Volt applications and three phase 480 Volt (or "fast charging") applications.

The basic concept for grid related services provided by EV/PHEVs is called Vehicle-To-Grid (V2G). V2G charging enables EV/PHEVs to receive electricity from the electric grid and also to send electricity onto the electric grid, thereby acting as distributed, mobile energy storage.

Most consumers would likely charge their vehicles at night during a utility's off-peak period when conventional electricity demand is the lowest, when electricity is the cheapest, and when most utilities have idle capacity. Thus, EV/PHEVs can also provide valuable grid services such as spinning reserves or regulation, reducing the need to rely on generators.

A V2G system could be a significant driver of large-scale incorporation of intermittent renewable energy into the grid. EV/PHEV storage could help balance the normal fluctuations of demand and intermittent renewable supply. In particular, wind power can benefit greatly from distributed storage such as V2G. V2G is also well-suited to providing stabilizing and emergency services for the utility grid. Specifically, the nearly instant response time of the battery makes V2G well-suited for providing the second-by-second balancing of generation to load (frequency regulation) and for ensuring that sufficient generation capacity is available in the event of a power station or transmission failure (spinning reserves). Historically, these ancillary services have been provided by reserving some capacity of traditional thermal plants, but currently in California, roughly half of the services are provided by bidders in the independent system operator (ISO) market. The market clearing prices for these services are much greater than wholesale electricity prices making ancillary services an attractive initial market for up to tens of thousands of V2G capable vehicles.

PHEV/EV batteries can be used to store excess renewable energy to be supplied back to the grid in times when the energy is needed. The use of PHEVs as mobile storage devices has the potential to significantly change a utility's load shape. PHEVs alone will increase nighttime load, thereby flattening a utility's daytime load.

It should also be noted, though hard to quantify, by increasing vehicle fuel efficiency, EV/PHEV reduces the use of and dependence on gasoline and lowers emissions including CO2, NOx, Sox, and PM-10. Last, EV/PHEV owners may also receive substantial revenue by using the stored energy in their vehicles to provide high-value electric system services such as regulation, spinning reserve, and peaking capacity; whereby V2G makes this possible.

The state of California has approximately 1,300, 240V, single phase charging stations that can fully charge battery EVs overnight and large battery PHEV/PEVs in a few hours. The Energy Commission has allocated $15.3 million with matching federal stimulus funds of $55.8 million to install more than 4,000 stations.[52]

PEV charging as it relates to load management or load shifting is being analyzed by utilities and automotive manufacturers to further develop common standards to enable the PEVs to act as just another appliance on the AMI or HAN.

Benefit to Cost Ratio of V2G Charging Approaches

A study conducted by SilverSprings Networks in 2010 outlined the following three costs to benefit ratio scenarios for V2G charging to enable utilities to understand how V2G is best implemented. The first utility owned V2G where the utility pays for, owns, operates and maintains the V2G equipment, with an internal meter. The second, the customer purchases, owns, installs, operates and maintains the V2G equipment with an internal meter. There is also an option where the customer owns the V2G equipment and pays to install it, but the utility installs a separate meter. The third scenario is where the utility takes no responsibility for the V2G. Scenario 2 looks like it has the best benefit to cost ratio, but customer ownership of the meter may make this scenario unfeasible for the utility, so the utility therefore would install its own meter. Once the model incorporates the cost to the utility of installing its own meter, as Scenario 2a does, Scenario 2 becomes less cost effective and Scenario 1 is more attractive. Figure 21 shows the cost benefit ratio of each scenario and the associated benefits.

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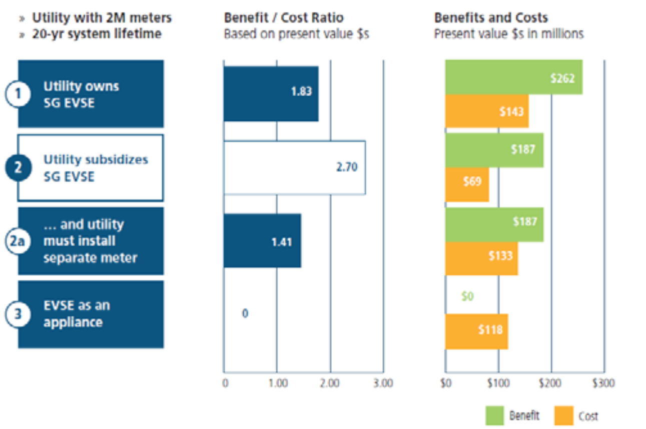
52 California Energy Commission Staff and Statewide Plug-In Electric Vehicle (PEV) Collaborative PEV Infrastructure Joint Workshop, October 19, 2010.

Figure 21: Benefit to Cost Ratio of V2G



Driver	Benefit	Scenario 1	Scenario 2	Scenario 2a
Peak control	Reduces cost of peak generation	Yes	Yes	Yes
	Reduces cost of transmission and distribution expansion	Yes	Yes	Yes
	Lowers energy cost due to shifting EV charging to non-peak times (set number of peak days per year)	Yes	Yes	Yes
Load scheduling or time-of-use rates	Lowers energy costs by shifting loads to non-peak times (ongoing as needed)	Yes	Depends on customer engagement	Depends on customer engagement
Load scheduling	Maintains local distribution network reliability	Yes	No	No
	Supports integration of more renewable energy	Yes	No	No
EVSE ownership	Greenhouse gas abatement credits	Yes	No	No

Benefits of V2G Charging

Utility-controllable DER can be used for load shifting, demand response, and pricing-signaling purposes. All applications which may provide reverse flow power capability such as V2G are unproven. Because of this, we have excluded direct quantifiable benefits associated with it in the framework. V2G remains a R&D agenda item of several automotive manufacturers, EPRI, ISOs/RTOs, and several utilities.

Additional benefits that could potentially be supported by V2G charging, and supporting PHEV/EV or storage applications in the future are discussed below.

Optimized Generation Optimization: EV/PHEV electric storage can be used to absorb generator output as electrical load decreases (buffer renewable energy excess energy to enhance supply quality) allowing the generators to remain in their optimum operating zone. The stored electricity could then be used later so that dispatching additional less efficient generation could be avoided. The storage could help smooth the generation load curve. In the end, this avoids startup costs as EV/PHEVs increase the load on the system which reduces generator cycling, improves performance/efficiency and shaves load.

Deferred Generation Capacity Investments: EV/PHEV electric storage could generation during system peaks, improving the overall load profile as well as enable efficient generation mixes to be dispatched, saving utilities money on generation purchases.

Reduced Ancillary Service Payments: EV/PHEV or fast responding DER reduce the amount of reserve margin required, or required capacity above the peak demand (typically +15 percent).

Deferred Transmission Capacity Investments: Transmission is typically overbuilt to meet peak load which occurs only during certain portions of the year. Providing the stored energy of EV/PHEVs to the grid, close to its end use, will reduce power flow on the lines and deferring capacity upgrades (mainly during system peaks).

Deferred Distribution Capacity Investments: EV/PHEV storage can be used to relieve overloaded feeders and load, deferring the capital required to make the necessary upgrades.

Reduced Congestion Costs: EV/PHEVs are distributed energy resources which are located near the end use of electricity; thus less electricity is passed through the T&D lines, reducing congestion.

Reduced Sustained Outages: EV/PHEV storage can be used as back-up power (for a few hours only) in the event of a customer outage.

Reduced CO_2, Sox, NOx, and PM-10 Emissions: EV/PHEV reduced the amount of CO_2 per mile driven, provided the carbon released by the generation is lower than that of gasoline. In addition, the reduction in peak demand also reduced emissions due to the generation mix serving peak demand.

Reduced Oil Usage/ Displaced fuels: EV/PHEVs increase fuel efficiency, reducing the required oil per mile required.

Reduced Electricity Cost: PHEV/EV and V2G can lower energy cost by shifting EV charging to non-peak times (set number of peak days per year). When the price of power is high, consumers that own EV/PHEVs and have stored energy realizes savings on his/her electric bill based on on/off-peak pricing differentials.

Increased Asset Utilization: In the future, utility may be able to use expensive baseload plants to fuller capacity through the overnight charging of electric vehicles.

Costs of V2G Charging

It is too early to predict the exact costs of V2G. Such costs for a utility to consider would include V2G hardware and embedded firmware, software, including the EV management software on the utility side and the customer portal, installation, excluding customer service panel upgrades if required, start-up program costs, including software system integration and project management, ongoing costs for program operation, including expenses for call centers, IT, asset and inventory management.

EPRI estimates the per-PEV infrastructure costs will be between $25 and $50 for long-term and short-term volumes respectively. The communication costs required (either PLC or Zigbee) are estimated at between $10 and $20 per vehicle in the near term and far term, respectively.

Residential HEMs are estimated between $150 and $300 per customer to enable them to manage their PHEV/EV and charging. The vehicle to grid inverter cost is estimated at $400 per vehicle inverter.

Table 27: V2G Charging Costs and Assumptions

PEV Infrastructure	$25-50/customer
Residential EMS	$150 and $300/customer
Communications to Vehicle	$10-20 /vehicle

Recommendation to the Commission:

- The Commission should continue to analyze the costs and benefits associated with V2G and test the viability of PHEV/EV generating efficiently back to the grid. Grid challenges should also be analyzed for large scale deployments as well as the development of tariff rate structures to accommodate mass deployments.
- Utilities should proactively assess how to manage the adoption and charging of EVs within their service territories. When evaluating different EV integration options, utilities should consider variables such as who owns the EVSE, who owns the meter used for EVSE billing, and how electricity rates can influence consumers' EV charging behavior.

Use Case 7: Asset Management - Asset Monitoring Enables Proactive System Planning and Maintenance

Monitoring throughout the full system has the potential to reduce energy losses, improve dispatch, enhance stability, and extend infrastructure lifespan. For example, monitoring enables timely maintenance, more efficient matching of supply and demand from economic, operational and environmental perspectives, and overload detection of transformers and conductors. Not only smart meters but advanced sensors, synchrophasors, and distribution automation systems are examples of equipment that are likely to be even more important in harnessing the value of Smart Grid.

Monitoring substation, transmission and distribution system assets using advanced technology enables utilities to preventatively make system alterations to improve reliability, quality of service and operating efficiencies by preventing failures. Improved knowledge of the condition of equipment and stresses will enable utilities to better manage the assets. Sensor data used together with historic performance information, failure databases and operational data allows better allocation of resources.

Benefits of Asset Management

Asset management can improve capital expenditure plans, reduced system losses, improve system reliability through avoided equipment failures, increased asset life and utilization factor and reduced maintenance and inspection costs. Asset management offers the following benefits:

- Increased Diagnostics
  Automatic Condition Based Maintenance can increase early fault detection through advanced monitoring applications such as sensors that could reduce equipment failures by 75 percent.
- Reduced Equipment Failures & Replacement
- Maximize Asset Life

- Deferred T&D Capacity Investments
- Reduced System Losses - Transformer Load Management
- Improve system reliability and performance - Transformer Load Management
- Reduce O&M Costs

Costs of Asset Management

Asset management of the electrical system leverages previously installed SCADA systems. As previously mentioned, we estimated SCADA upgrades at $170 per customer based on EPRI's estimated costs from actual utility clients and is in line with work we've completed with other utility clients. Utilities will need to consider costs for advanced IEDs, sensors, relays, reclosers, RTUs, capacitor banks, regulators, and LTCs to ensure proper communication of asset status. More advanced systems may implement a DMS system ($150 per customer). DMS costs are estimated based on cost benefit analysis conducted for other utility clients and proposals received from DMS vendors.

Table 28: Asset Management Costs

SCADA	$ 170/customer
DMS	$ 150 /customer
Devices: IEDs, sensors, relays, reclosers, RTUs, capacitor banks, regulators, LTCs	$ 50 /customer

Steps to Developing a Detailed Smart Grid Business Case

As we have presented a high-level framework for POUs, the following are the five steps necessary to build a detailed Smart Grid Business Case model for the Use Cases identified. Note that each step takes a considerable amount of time and effort to accurately represent the cost and benefits of a Smart Grid investment.

1. **Project Characterization**
    - Define the project's purpose, goals, objectives, and primary benefits; for example, what is the business opportunity and/or problem to address?
    - Define the scope; such as, geographic, organizational, beneficiaries, timing, and so forth.

2. **Define Smart Grid Functions**
    - Identify, from a standard set of Smart Grid functions, the Smart Grid functionality required to address the problem and/or realize the business opportunity
    - Identify preliminary Smart Grid technologies/assets to be implemented
    - Map each Smart Grid function into standardized benefit categories
    - Confirm Smart Grid technologies/assets to be implemented

3. Define and Quantify the Cost and Benefits

- Define and collect baseline data and costs associated with the expected Smart Grid functionality
- Quantify the benefits, identify risks and qualitative benefits

4. Compare Costs and Risks to Benefits

- Estimate the relevant recurring and non-recurring incremental costs
- Compare costs and risks to benefits
- Determine how benefits will be measured and reported
- Prepare value capture and reporting plan
- Document assumptions

5. Make Recommendations

- Document the results of the analysis in the business case
- Create an executive summary and present recommendation for approval

CHAPTER 6: Smart Grid 2020 Technology Roadmap

The guidance provided in this report is embodied in a series of roadmaps. These include:

- Smart Grid Maturity Model (SGMM) Roadmap
- Two POU Technology Roadmaps, one for Leaders and one for Followers
- Seven POU Implementation Roadmaps for each of the two Technology Roadmaps

The roadmaps do not include everything a utility will want to know, however. Some recurring activities are omitted, simply because they would clutter the roadmaps with repetitive content. But the recurring activities are no less important than the sequential activities described below and sequenced in the roadmaps. The recurring items are discussed following the roadmap paragraphs.

The SGMM Roadmap

Making the SGMM Roadmap

As discussed in detail in Chapter 3 of this report, the Smart Grid Maturity Model (SGMM) defines a wide range of characteristics of utility organizations at various stages of maturity in implementing smart grid. The model is an extremely useful tool that provides penetrating insight into a utility's progress toward a full Smart Grid position.

For this report, SAIC created a roadmap from the content of the SGMM. As discussed in Chapter 3, the SGMM defines "expected characteristics" that describe a utility at each of the five levels of Smart Grid maturity. By summarizing and converting the stated characteristics at each level into action statements, a roadmap to achieving that level is readily constructed. For example, the SGMM characteristic:

- Smart Grid strategy is shared and revised collaboratively with external stakeholders

can be stated as a process step by writing, "Share the Smart Grid strategy with external stakeholders and collaborate with them to revise it."

As another example, the characteristics,

- Pilots of remote AMI/AMR are being conducted or have been deployed.
- Security and privacy requirements for customer protection are specified for smart grid-related pilot projects and RFPs.

can be restated as "Conduct pilot tests of AMI/AMR and define associated customer security and privacy requirements."

In this way, SAIC produced the roadmap shown in Figure 22, summarizing the content of the SGMM levels in each of the 8 domains and turning it into an action plan outline.

Figure 22: SGMM Roadmap

SGMM Domains	SGMM Levels				
	Initiating	Enabling	Integrating	Optimizing	Pioneering
Strategy, Management, and Regulatory (SMR)	Develop smart grid vision to improve operations/ efficiency	Align smart grid strategy/budgets with operational funding for smart grid implementation	Establish smart grid governance model & secure authorizations for smart grid investments	Share & evolve smart grid strategy collaboratively with board/regulators.	Capitalize on smart grid as a foundation for introduction of new services/product offerings
Organization and Structure (OS)	Demonstrate commitment and initiate awareness in the workforce to support smart grid activities	Form & charter smart grid teams involving employees from every department.	Link employee compensation to smart grid success.	Enable decision making as a result of an efficient organizational structure and increased availability of information	Organization and its structure readily adapts to support new ventures/ products/services as a result of smart grid
Grid Operations (GO)	Evaluate/test new DA devices and communications technologies for grid monitoring and control	Implement advanced outage restoration schemes.	Enable automated decision-making leveraging increased analytic capabilities and context	Grid operational management is based on near real-time data across the organization	Expand automated grid decision making to control devices system-wide.
Work and Asset Management (WAM)	Evaluate remote asset monitoring and workforce and asset management technologies aligned to the smart grid vision	Develop strategy for asset monitoring using smart grid capabilities and mobile workforce management	Integrate field equipment monitoring with mobile workforce systems to automate work order creation/ resolution.	Asset models and maintenance are based upon real performance and monitoring data on key components	Optimize asset life and utilization based on smart grid data and systems
Technology (TECH)	Define enterprise IT architecture applicable to all IT systems.	Select standards/processes that support the smart grid strategy within the enterprise IT architecture	Implement smart grid-specific technology that is aligned with the enterprise IT architecture to improve cross-functional performance	Optimize business processes leveraging the enterprise IT architecture	Complete IT that systems automatically identify, mitigate, & recover from cyber incidents.
Customer (CUST)	Research use of smart grid technologies to enhance customers' experience/benefits, & participation	Pilot test AMI, new service and delivery options	Deploy AMI, demand response, & direct load control.	Enable customer loads to respond automatically to prices, programmed by customer preferences.	Enable customers to manage their end-to-end energy supply and usage levels
Value Chain Integration (VCI)	Create a strategy to deploy & integrate distributed generation, storage, load management.	Pilot test DER/DG integration	Enable DER/DG resources to support grid reliability and other objectives	Communicate securely with customer home networks & loads.	Enable automated control and resource optimization schemes to support regional/national grid optimization
Societal and Environmental (SE)	Publicly promote the sociatal/environmental benefits of the smart grid vision/strategy	Implement proof-of-concept projects to demonstrate smart grid benefits to the public/environment	Deploy programs to encourage customers to use energy off-peak. Provide info on environmental & societal benefits & costs.	Enable customers to actively manage end-usage & devices and therefore consumption through the enterprise network	Enable customers to control their energy-based environmental footprint through automatic optimization of their end-to-end energy supply and usage level based on customer-selected preferences

AMI: Advanced Metering Infrastructure
DA: Distribution Automation
DER: Distributed Energy Resources
DG: Distributed Generation
IT: Information Technology

Timing in the SGMM Roadmap

The grid of actions shown in Figure 22 can be imagined as a timeline. But this may not work well, and it's useful to think about such a timeline to see why. This will help in understanding the Technology and Implementation roadmaps that follow this.

The SGMM levels shown across the top row of Figure 22 are sequential. That is, within each of the eight domains, the activities in one level must precede the higher level activities. With this in mind, a POU may imagine putting dates on the levels in the top row of the figure. For example, a POU might plan to reach full Smart Grid maturity in about 2030, and might therefore plan that:

- Initiating will be conducted during 2012 through 2014.
- Enabling will be conducted during 2015 through 2018.
- Integrating will be conducted during 2019 through 2024.
- Optimizing will be conducted during 2024 through 2028.
- The utility will be Pioneering will by 2030 and beyond.

But there's a problem with this: Activities in some domains must precede activities at the same level of other domains. For example, in the Integrating level (Level 3), the Strategy, Management, and Regulatory domain includes the work to:

> Establish Smart Grid governance model and secure required authorizations for investments in Smart Grid from stakeholders.

For most utilities, it will be productive to do this before the following activities in the Customer and Societal and Environmental domains, respectively:

> Deploy AMI, demand response, & direct load control,

and

> Deploy programs to encourage customers to use energy off-peak.

Both of these are shown in the same level—Integrating—as the governance model and investment authorization. But how is a utility to deploy AMI and associated programs without first having established an overall governance model and obtained approval for the AMI and program investments? It is not impossible. Because, many Smart Grid investments can be pursued as stand-alone projects. Thinking only of benefits in metering, billing, and customer service, a utility can deploy meter automation without regard to other benefits, and without coordinating the technology with other technology investments. The approach may complicate, or sacrifice altogether, some benefits that arise from integrating AMI with other systems. Many utilities have done exactly that as they pursued the benefits of automation in the various "silos" within the utility.

The Smart Grid thesis is that coordinating these pursuits will produce benefit that is greater than the sum of its parts. To achieve that, a utility will plan ahead—exactly as the California POUs are doing now—and that planning will stage the activities in Figure 22 in a time sequence that may, for many utilities, stagger the rows of the SGMM roadmap table in time.

Technology Roadmap

The SGMM comprehensively addresses organizational and business information technology (IT) matters. Its insight is less detailed into the electrical and electronic technologies of utility automation, and the IT resources that support them. The Technology Roadmap approach by SAIC for this project emphasizes these elements. From the perspective of utility automation of electric energy creation and delivery, the central threads of Smart Grid implementation are found in the Technology Roadmaps shown in Figure 23 and Figure 24. POU planners will recognize the additional need for the SGMM business activities, and will use the SGMM roadmap of Figure 22 as a complementary planning tool.

Figure 23: Technology Roadmap - Leaders

Use Cases	Key Milestones to Achieve 2020 Smart Grid Vision				
	2011-2012	2013-2014	2015-2016	2017-2018	2019-2020
Substation Automation	Pilot test automated protection control devices/technologies.	Analyze pilot results. Expand SCADA/SA to support protection automation. Acquire software for integrated distribution management, protection and control.	Apply automated protection at substation scale, integrated with other distribution automation.	Integrate circuit reconfiguration with automated protection. Expand protection strategy to other substations.	Integrate real-time analysis with dynamic protection and control.
Advanced Metering / Demand Response	Complete deployment of AMI, MDMS and web portal. Pilot dynamic rate/incentive programs	Expand telecomm infrastructure to support HANs, IHDs. Acquire software for integrated DRMS. Pilot with dynamic rate programs, DR/DLC devices	Pilot integrated/automated management of DR/DLC, DER and DG resources. Extend dynamic rate/incentive programs to all customers	Extend deployment of DR/DLC technologies to all customers. Conduct real-time dynamic optimization of DR, DER & DG resources for system reliability events.	
Distributed Energy Resources	Plan & pilot test DER & VVO. Refine engineering models.	Analyze pilot results. Acquire software for integrated DER/distribution management.	Begin system-wide DER & VVO; pilot test integrated distribution control.	Extend dynamic rates to all DER customers. Offer HAN support. Integrate distribution resources.	Integrate real-time engineering analysis with distribution operations.
Distribution Automation - Automated Feeder Management	Pilot test feeder automation and management technologies	Analyze pilot results. Expand SCADA/SA to support advanced FM. Acquire software for automated feeder management with FLISR capability.	Expand deployment of feeder monitoring/ automation technologies. Pilot automated system topology reconfiguration for system reliability.	Expand feeder automation and monitoring to other substations. Conduct real-time analysis to reconfigure system topology for self-healing grid operations.	
Distribution Automation - Integrated Voltage Management	Pilot test automated voltage management technologies.	Analyze pilot results. Expand SCADA/SA to support advanced VM. Acquire software for integrated VM.	Expand deployment of voltage monitoring & management technologies. Pilot integrated/automated VVO/CVR for system realibility.	Expand VM and monitoring to other substations. Conduct real-time dynamic VM operations on equipped distribution segments.	
Electric Vehicle Charging	Pilot test EV integration and protection and control technologies.	Pilot dynamic rate/ incentive programs. Analyze grid impact. Acquire software for advanced DER/EV control.	Pilot management of EV resources for DR and system reliability events.	Dynamically manage EV resources for DR and system reliability events.	
Asset Management	Pilot test asset monitoring and sensing technologies.	Analyze pilot results. Expand SCADA/SA to support asset monitoring /management. Acquire condition-/performance-based asset maintenance/ management solution.	Apply integrated asset management/maintenanc e on select asset classes.	Expand system-wide deployment of asset monitoring and management technologies.	Integrate real-time analysis with resource planning

AMI: Advanced Metering Infrastructure
CVR: Conservation Voltage Regulation
DA: Distribution Automation
DER: Distributed Energy Resources
DG: Distributed Generation
DLC: Direct Load Control
DR: Demand Response
DRMS: Demand Response Management System
EV: Electric Vehicle
FLISR: Fault Location, Isolation and Service Restoration
FM: Feeder Management
HAN: Home Area Network
IHDs: In-Home Displays
MDMS: Meter Data Management System
SA: Substation Automation
SCADA: Supervisory Control and Data Acquisition
VM: Voltage Management
VVO: Volt / VAR Optimization

Figure 24: Technology Roadmap - Followers

Use Cases	Key Milestones to Achieve 2020 Smart Grid Vision				
	2011-2012	2013-2014	2015-2016	2017-2018	2019-2020
Substation Automation	Develop business case for SA& DA.	Construct engineering models. Test micro-processor relays & reclosers. Invest in SCADA/SA.	Pilot automated protection & control thru SCADA. Develop implementation plans based on pilot results	Expand communications infrastructure, protection and control technologies to other feeders/substations. Acquire/ deploy/test software for automated protection and control.	
Advanced Metering / Demand Response	Develop business case for AMI & DR.	Test 2-way metering and communication technologies. Pilot rate & incentive programs for customers for DR.	Pilot AMI & HAN communication technologies with DR. Develop implementation plans based on pilot results.	Invest in/expand telecommunications and smart metering infrastructure to support AMI & DR/DM operations. Acquire/ deploy/test software for DR/DLC management.	
Distributed Energy Resources	Develop business case for DER/DG integration.	Pilot net-metering and rate & incentive programs for DER/DG customers. Invest in SCADA/SA	DER/DG integration & voltage regulation technologies.	Extend rate/incentive programs and pilots. Acquire software for integrated DER/distribution management.	Extend DER & VM deployments; pilot test integrated DER/DG and distribution management.
Distribution Automation - Automated Feeder Management	Develop business case for SA & DA.	Construct engineering models. Test feeder automation and management technologies. Invest in SCADA/SA	Pilot automated FM & fault detection thru SCADA. Develop implementation plans based on pilot results.	Expand communications infrastructure, feeder automation and management technologies to other feeders/substations. Acquire/ deploy/test software for automated FM.	
Distribution Automation - Integrated Voltage Management	Develop business case for SA & DA.	Construct engineering models. Test automated voltage management technologies. Invest in SCADA/SA	Pilot automation hardware & controllers for VM. Develop implementation plans based on pilot results.	Expand communications infrastructure, VM and monitoring technologies to other feeders/substations. Acquire/ deploy/test software for integrated VM.	
Electric Vehicle Charging	Develop business case for EV integration to the grid.	Pilot net-metering and rate & incentive programs for EV customers. Invest in SCADA/SA.	Pilot EV integration & voltage regulation technologies.	Extend rate/incentive programs and pilots. Acquire software for integrated EV & distribution management.	
Asset Management	Develop business case for SA & DA.	Construct engineering models. Test asset monitoring and sensor technologies. Invest in SCADA/SA	Pilot remote asset monitoring, visualization technologies & predictive maintenance practices. Develop implementation plans based on pilot results	Expand communications infrastructure, asset monitoring and management technologies to other feeders/substations. Acquire/deploy/test software for condition-based asset management and maintenance.	

AMI: Advanced Metering Infrastructure
DA: Distribution Automation
DER: Distributed Energy Resources
DG: Distributed Generation
DLC: Direct Load Control
DR: Demand Response
DM: Demand Management
EV: Electric Vehicle
FM: Feeder Management
HAN: Home Area Network
MDMS: Meter Data Management System
SA: Substation Automation
SCADA: Supervisory Control and Data Acquisition
VM: Voltage Management

The two figures show the Technology Roadmap for two different POUs respectively:

Figure 23 is for an innovative utility that chooses to lead the charge into smart grid, and Figure 24 guides a more conservative POU that elects to follow that lead from a position farther back in the pack. The Leader, as described elsewhere in this report, by 2011 has already planned some Smart Grid implementations, has either planned or is conducting some pilot tests, and may be deploying some field resources or IT integration projects. The follower maintains a robust distribution plant, focuses on reliable, low cost service, and is responding to the national Smart Grid progress—highly visible in the trade press—by initiating its Smart Grid planning now.

In each Technology Roadmap, the columns show the five two-year time intervals from now to 2020. The rows correspond to the Use Cases discussed in Chapter 4 of this report. These use cases embody most of the Smart Grid functions and elements a POU will want to address. In each box, corresponding to a two-year period for a specific use case, the text describes the activities a POU will accomplish in fulfilling the role of Leader or Follower in Smart Grid deployment. By choosing individual use cases, POUs can focus on the parts of these Roadmaps that are most closely aligned with their near-term and longer-term goals.

But what of the other use cases? The others will follow. Recall that the thesis of Smart Grid is that coordinating these pursuits will produce benefit that is greater than the sum of its parts. Implementing some of these use cases in a planned and coordinated way, as described in these Roadmaps, positions the POU to more readily implement the other use cases. That is why the value produced is higher than it will be if they are implemented independently. When coordinated, creating one enables another, reducing the cost of the successor implementations. And the synergies among coordinated implementations produce value that is not produced by independent projects.

Like the SGMM roadmap, the Technology Roadmaps are summaries of the overall sequence and process of being a Leader and Follower in smart grid. More detail is needed to portray all the steps required to implement this process. The Implementation Roadmaps discussed below, describe the detailed steps appropriate to support execution of each Technology Roadmap.

Implementation Roadmaps

The Technology Roadmaps described above focus on the hard technology for automating delivery of electric energy, and on the IT for managing that delivery. Many other supporting steps are essential to enable technology success. These steps occur in areas that enable and support the principal Smart Grid technologies named in the Technology Roadmaps, and are defined in the following strategic focus areas:

- Planning
- Communications Infrastructure
- Instrumentation, Control & Automation
- Information Technology

- Standards
- Training

The Implementation Roadmaps provide detailed instructions in these six focus areas, leading step-by-step to establish essential planning, supporting infrastructure and IT, and finally the Smart Grid content for each of the use cases.

The Implementation Roadmaps are shown in their full detail following this section. To assist readers in understanding them, summaries of the Implementation Roadmaps are presented below as well of this report. These summaries combine the last two focus areas into a single area for Standards & Training. In each two-year time interval for each focus area, the Implementation Roadmap Summaries distill the content of the full Implementation Roadmaps into a few key words identify the most prominent actions. It is important to note that, in the interest of brevity and overview, some actions are omitted from the summaries. This makes the overall direction and content of each roadmap more accessible, which is helpful when reading to grasp direction and plan strategy. But readers shall refer to the full details following this section when planning activities.

Figure 25: Implementation Roadmap Summary - Substation Automation - Leader

	Key Milestones to Achieve 2020 Smart Grid Vision				
Strategic Focus Areas	**2011-2012**	**2013-2014**	**2015-2016**	**2017-2018**	**2019-2020**
Planning	Refine engineering protection models. Evaluate pilot results. Plan feeder-scale tests.	Analyze feeders. Determine protection settings for diverse operating environments.	Deploy & assess substation-scale automated protection.	Plan & initiate system-wide deployment based on pilot results.	Refine engineering models to support near real-time dynamic protection.
Communications Infrastructure	Expand telecommunications infrastructure to support proper protection & control operations.				
Instrumentation Control and Automation	Pilot microprocessor-based relay & recloser controls coordinated thru SCADA.	Assess pilot results. Expand SCADA & substation automation to support broader protection automation. Expand pilots with advanced protection technologies for DER/DG integration	Expand protection pilots to other substations & feeders. Determine cost/benefits with DG, storage, & EV charging.	Expand pilots to other substations & feeders for integrated system protection and control. Determine costs/benefits.	
Information Technology	Refine geospatial connectivity model and implement/integrate with OMS. Evaluate architecture options & integration needs for automated protection and control.	Procure/integrate/deploy a master or distributed distribution management software for automated protection and control.	Conduct pilots of integrated / automated protection. Assess costs / benefits.	Integrate circuit reconfiguration & protective device control thru master DMS station.	Integrate real-time analysis with distribution management approach for operational control.
Standards & Training	Evaluate /adopt/implement standards for integrated protection & control monitoring. Refine equipment selection.	Train operating staff on master station software for automated protection and control capability.	Participate in standards advancement. Expand training.	Advance training as needed to operating and engineering staff for integrated distribution operations and protection.	

DER: Distributed Energy Resources DMS: Distribution Management System OMS: Outage Management System
DG: Distributed Generation EV: Electric Vehicle SCADA: Supervisory Control and Data Acquisition

Figure 26: Implementation Roadmap Summary - Substation Automation - Follower

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision				
	2011-2012	**2013-2014**	**2015-2016**	**2017-2018**	**2019-2020**
Planning	Develop business case for SA& DA.	Construct engineering models for pilots.	Refine engineering models based on pilots. Develop implementation plans based on pilot results.	Design feeder deployments based on engineering & reliability analysis.	Plan system-wide deployment for integrated protection management.
Communications Infrastructure	Assess telecommunications infrastructure to support asset monitoring and management.	Procure/test communication system elements.	Pilot communication technologies.	Invest in/expand telecommunications infrastructure to support automated protection & control operations.	
Instrumentation, Control & Automation	Identify/select smart grid technologies to prototype/test with.	Invest in SCADA/SA. Test micro-processor relays & reclosers.	Pilot protection & control functionality thru SCADA.	Advance pilots to feeder and substation levels. Determine costs/benefits.	
Information Technology	Select network modeling technologies.	Develop geospatial network model. Implement OMS & IVR.	Evaluate a master or distributed software suite for automated protection & control.	Procure/deploy/test a master or distributed software suite for automated protection and control.	
Standards and Training	Evaluate standards for communications, control & security. Assess staff and training needs.	Develop training plan for staff on protection & control monitoring. Train staff on network modeling and OMS/IVR systems.	Adopt / implement standards. Train technicians on protection & control monitoring and engineers on reliability analysis.	Extend training as needed to engineering staff on master/distributed system software for automated protection & control monitoring and management.	

DA: Distribution Automation
OMS: Outage Management System
IVR: Interactive Voice Response
SA: Substation Automation
SCADA: Supervisory Control and Data Acquisition

Figure 27: Implementation Roadmap Summary - Advanced Metering and Demand Response - Leader

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision				
	2011-2012	**2013-2014**	**2015-2016**	**2017-2018**	**2019-2020**
Planning	Plan overall sequence of pilot tests & deployments of rate & incentive programs for customers. Communicate/educate/enroll customers. Evaluate pilot results. Modify programs to enhance productivity.		Extend dynamic rate & incentive programs for all customers. Extend communication/ education/ enrollment to all customers.		Evaluate / revise customer programs results vis-à-vis revenue requirements.
Communications Infrastructure	Expand telecomm resources to support AMI, HANs, IHDs, DR, load control.			Enhance telecomm to support customer appliance communication.	
Instrumentation, Control & Automation	Complete 2-way metering deployment. Pilot test dynamic rate programs, demand response, & direct load control.		Extend dynamic rates & load control to all customers. Expand pilots to include HANs & IHDs. Measure changes in load/demand related to direct load control, DR & load management events. Determine		Begin pilot tests with "smart" customer appliances.
Information Technology	Procure/deploy/test AMI head end systems, MDMS & web portal approach. Integrate web portal with automated solutions.	Integrate customer service applications with automated solutions. Procure / integrate / deploy a master or distributed DRMS.	Conduct pilots for integrated & automated DR/load control of DR, DG & DER resources.	Conduct real-time analysis to optimize control and management of DER, DG & DR resources for DR/load control/management and system reliability events.	
Standards and Training	Evaluate /adopt/implement standards for customer service. Refine equipment selection. Identify needs & develop training. Train operations personnel on AMI, MDMS, customer web portal, and customer service personnel on advanced services (rate programs, DR/load control and management programs).		Participate in standards advancement. Expand training.	Advance training for personnel for near real-time engineering analysis to enable dynamic management of DR,DG, and DER resources. Reevaluate workforce needs.	

AMI: Advanced Metering Infrastructure
DR: Demand Response
IHDs: In-Home Displays
DER: Distributed Energy Resources
DRMS: Demand Response Management System
DG: Distributed Generation
HAN: Home Area Network
MDMS: Meter Data Management System

Figure 28: Implementation Roadmap Summary - Advanced Metering & Demand Response - Follower

	Key Milestones to Achieve 2020 Smart Grid Vision				
Strategic Focus Areas	**2011-2012**	**2013-2014**	**2015-2016**	**2017-2018**	**2019-2020**
Planning	Develop business case for AMI & DR.	Pilot rate & incentive programs for customers. Communicate/educate/ enroll customers.	Develop implementation plans based on pilot results.	Extend pilot rate incentive programs for customers. Communicate/educate/ enroll customers.	Plan system-wide deployment for advanced customer service.
Communications Infrastructure	Assess telecommunications infrastructure to support 2-way metering.	Procure/test 2-way communication system elements.	Pilot AMI & HAN communication technologies.	Invest in/expand telecommunications infrastructure to support AMI & DR/DM operations.	
Instrumentation, Control & Automation	Identify/select 2-way metering, IHDs, HAN, & direct load control devices to prototype/test with.	Test 2-way metering, IHDs, HANs & direct load control devices.	Pilot 2-way metering, dynamic rate programs, & direct load control devices.	Advance pilots to feeder and substation levels. Measure load/demand. Determine costs/benefits.	
Information Technology	Determine CIS integration capabilities.	Update/replace CIS, if needed, for integration with AMI, web portals & DR.	Evaluate: AMI Head-end for 2-way metering; master/distributed solutions for web portal; master/distributed software suite for DR/DM, direct load control.	Procure /deploy/test AMI Head-end, MDMS (optional), master/distributed solution for web portal & master/distributed software for DR & load control management. Enhance integration among systems.	
Standards and Training	Evaluate standards for communications, control & security. Assess staff and training needs.	Develop training requirements for staff. Plan training for customer/utility interaction for smart grid	Adopt / implement standards. Train staff on advanced metering and communication technologies/systems for enhanced customer/utility interaction.	Extend training as needed to operating and customer service staff for advanced customer/utility interactions thru smart grid technologies.	

AMI: Advanced Metering Infrastructure DR: Demand Response
MDMS: Meter Data Management System CIS: Customer Information System HAN: Home Area Network
DM: Demand Management IHDs: In-Home Displays

Figure 29: Implementation Roadmap Summary - Distributed Energy Resources - Leader

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision				
	2011-2012	2013-2014	2015-2016	2017-2018	2019-2020
Planning	Plan feeder-scale DER/DG integration. Refine engineering models for DER/DG integration.	Analyze grid impact of DER/DG. Enroll customers in dynamic-rate DER programs.	Plan system-wide DER/DG integration.	Extend dynamic-rate programs to all DER/DG customers.	Refine engineering models to support near real-time dynamic DER/DG operations.
Communications Infrastructure	Expand telecommunications infrastructure to support DER/DG integration.		Expand HAN deployments to support advanced DER/DG control for DR and system reliability events.		
Instrumentation, Control & Automation	Conduct dynamic-rate net-metering DER/DG pilots with customer IHDs.	Analyze pilot results: bi-directional protection, LVRT and customer response.	Expand substation & feeder automation. Expand DER/DG pilots to feeder-/substation-scale.	Enable automated control of DER/DG resources for DR and system reliability events.	
Information Technology	Refine geospatial connectivity model. Evaluate architecture options & integration needs for automated distribution operations.	Procure/integrate/deploy a master or distributed distribution management and DER/DG Control/ Energy Management software suite.	Conduct pilots of integrated / automated VVO/CVR & advanced control of DER/DG resources for DR and direct load control.	Integrate real-time analysis with distribution management for real-time operational control of DER/DG resources in response to DR, direct load control and system reliability events.	
Standards and Training	Evaluate/adopt/ implement standards. Plan staff training for DER/DG integration technologies and VVO.	Train staff for integrated distribution management with DER and VVO.	Participate in standards advancement. Expand training.	Extend training as needed to operating & engineering staff for integrated distribution operations.	

AMI: Advanced Metering Infrastructure
DG: Distributed Generation
LVRT: Low Voltage Ride Through
CVR: Conservation Voltage Reduction
DR: Demand Response
VVO: Volt/VAr Optimization
DER: Distributed Energy Resources
HAN: Home Area Network

Figure 30: Implementation Roadmap Summary - Distributed Energy Resources - Follower

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision				
	2011-2012	2013-2014	2015-2016	2017-2018	2019-2020
Planning	Develop business case for DER & DG integration.	Pilot rate & incentive programs for DER/DG customers. Communicate/educate/ enroll customers.	Plan feeder-scale DER/DG integration. Construct/refine engineering models for DER/DG integration.	Extend rate/incentive programs, include feed-in tariffs. Determine impact of DER/DG deployments on grid.	Plan & initiate system-wide deployment based on pilot results.
Communications Infrastructure	Assess telecommunications infrastructure to support DER/DG integration.	Procure/test communication system elements.	Pilot communication technologies.	Invest in/expand telecommunications infrastructure to support DER/DG integration.	
Instrumentation, Control & Automation	Identify/select metering and DER/DG integration technologies to pilot with. Procure/deploy/test net metering technologies.	Pilot net metering technologies & IHDs. Test power inverter technology, voltage sensors/regulators & controllers for DER/DG integration. Invest in SCADA/SA	Pilot power inverter technology for DER/DG integration & voltage regulation.	Advance pilots with feed-in tariffs, net metering to feeder and substation area deployments. Track grid impact. Determine costs/benefits.	Advance pilots to other feeders & substations for integrated DER/DG management. Determine costs/benefits with DR & system reliability.
Information Technology	Select network modeling technologies.	Develop geospatial network/connectivity model.	Evaluate a master or distributed DER/DG and Volt/Var/CVR control systems. Evaluate system integration needs.	Procure/integrate/deploy a master or distributed DER/DG and Volt/Var/CVR control systems.	
Standards and Training	Evaluate standards for communications, control & security. Assess staff and training needs.	Develop training plan for staff on DER/DG integration technologies. Train staff on net-metering and engineering analysis and network modeling tools.	Adopt/implement standards. Expand training on DER/DG integration technologies.	Extend training as needed to distribution operating staff on master/distributed DER/DG and Volt/Var/CVR control systems.	

AMI: Advanced Metering Infrastructure DG: Distributed Generation SA: Substation Automation
CVR: Conservation Voltage Reduction IHD: In-Home Displays SCADA: Supervisory Control and Data Acquisition
DER: Distributed Energy Resources

Figure 31: Implementation Roadmap Summary - DA - Automated Feeder Management - Leader

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision				
	2011-2012	2013-2014	2015-2016	2017-2018	2019-2020
Planning	Refine engineering protection models. Evaluate pilot results. Plan feeder-scale tests.	Design feeder deployments based on engineering model analysis.	Deploy & assess feeder level FM operating tests.	Plan & initiate system-wide deployment based on pilot results.	Refine engineering models to support near real-time dynamic FM operations.
Communications Infrastructure	Expand telecommunications infrastructure to support automated feeder monitoring & management.				
Instrumentation, Control & Automation	Pilot FM components: sensors, FCIs,automated switches, & fault detection thru SCADA.	Assess pilot results. Expand SCADA & substation automation to support automated feeder management.	Expand pilots to other substations & feeders. Determine costs & benefits for business case.	Expand pilots to other substations & feeders for integrated FM operations. Determine costs/benefits.	
Information Technology	Refine geospatial connectivity model and implement/integrate with OMS. Evaluate architecture options & integration needs for automated feeder management.	Procure/integrate/deploy a master or distributed distribution management software for automated FM with FDIR capability.	Conduct pilots applying the master suite for automated system topology reconfiguration.	Conduct real-time analysis to reconfigure among multiple substations & feeders for self-healing grid operations.	
Standards and Training	Evaluate/adopt/implement standards for automated feeder management. Refine equipment selection.	Train operating staff on automated FM master station software.	Participate in standards advancement. Expand training.	Advance training to operating & engineering staff as technological complexity increases.	

FCIs: Fault Circuit Indicators FM: Feeder Management SCADA: Supervisory Control and Data Acquisition
FDIR: Fault Detection Isolation Restoration OMS: Outage Management System

Figure 32: Implementation Roadmap Summary - DA - Automated Feeder Management - Follower

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision				
	2011-2012	2013-2014	2015-2016	2017-2018	2019-2020
Planning	Develop business case for SA& DA.	Construct engineering models for pilots.	Refine engineering models based on pilots. Develop implementation plans based on pilot results.	Design feeder deployments based on engineering analysis.	Plan system-wide deployment for automated FM.
Communications Infrastructure	Assess telecommunications infrastructure to support automated feeder management operations.	Procure/test communication system elements.	Pilot communication technologies.	Invest in/expand telecommunications infrastructure to support automated feeder management.	
Instrumentation, Control & Automation	Identify/select smart grid technologies to prototype/test with.	Test feeder automation components: sensors, FCIs,automated switches, & fault detection. Invest in SCADA/SA	Pilot remote/automated FM functionality & fault detection/isolation thru SCADA.	Advance pilots to feeder and substation levels. Track grid impact. Determine costs/benefits.	
Information Technology	Select network modeling technologies.	Develop geospatial network model. Implement OMS & IVR.	Evaluate a master or distributed software suite for automated FM with FDIR capability.	Procure/integrate/deploy a master or distributed software suite for automated FM.	
Standards and Training	Evaluate standards for communications, control & security. Assess staff and training needs.	Develop training plan for staff on feeder automation. Train staff on network modeling and OMS/IVR systems.	Adopt/implement standards. Train technicians on FM and automation hardware.	Extend training as needed to distribution operating & engineering staff on master/distributed system software for automated FM capability.	

DA: Distribution Automation FM: Feeder Management SA: Substation Automation
FCIs: Fault Circuit Indicators IVR: Interactive Voice Response SCADA: Supervisory Control and Data Acquisition
FDIR: Fault Detection Isolation Restoration OMS: Outage Management System

Figure 33: Implementation Roadmap Summary - DA - Integrated Voltage Management - Leader

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision				
	2011-2012	2013-2014	2015-2016	2017-2018	2019-2020
Planning	Refine engineering models. Evaluate VM pilot results. Plan feeder-scale tests.	Design feeder deployments based on engineering analysis.	Deploy & assess feeder level VM operating tests.	Plan/initiate system-wide deployments based on integrated VM pilot results.	Refine engineering models to support near real-time dynamic VM operations.
Communications Infrastructure	Expand telecommunications infrastructure to support voltage monitoring & management operations.				
Instrumentation, Control & Automation	Pilot VM in component tests (sensors, controllers, regulators, LTCs & power inverters) and integrated control tests.	Assess pilot results. Expand SCADA & substation automation to support VM and/or VVO/CVR.	Expand grid VM pilots to other substations & feeders. Determine costs and benefits for business case.	Expand pilots to other substations & feeders for integrated grid voltage management. Determine costs & benefits with other smart grid operations, e.g.: DG, storage, & EV charging.	
Information Technology	Refine geospatial connectivity model. Evaluate architecture options & integration needs for automated grid optimization.	Procure/integrate/deploy a master or distributed distribution management software with integrated VVO/CVR functionality.	Conduct pilots applying the master suite for integrated / automated voltage management.	Conduct real-time analysis to optimize system voltage on equipped distribution segments.	
Standards and Training	Evaluate/adopt/ implement standards for grid optimization. Plan staff training for VM automation.	Train operating staff on integrated VM master station software.	Participate in standards advancement. Expand training.	Advance training to operating & engineering staff as technological complexity increases.	

CVR: Conservation Voltage Reduction
DG: Distributed Generation
EV: Electric Vehicle
LTCs: Load Tap Changers
SCADA: Supervisory Control and Data Acquisition
VM: Voltage Management
VVO: Volt/VAR Optimization

Figure 34: Implementation Roadmap Summary - DA - Integrated Voltage Management - Follower

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision				
	2011-2012	2013-2014	2015-2016	2017-2018	2019-2020
Planning	Develop business case for SA& DA.	Construct engineering models for pilots.	Refine engineering models based on pilots.Develop implementation plans based on pilot results.	Design feeder deployments based on engineering analysis.	Plan system-wide deployment for integrated voltage management.
Communications Infrastructure	Assess telecommunications infrastructure for voltage management.	Procure/test communication system elements.	Pilot communication technologies.	Invest in/expand telecommunications infrastructure to support voltage monitoring and management.	
Instrumentation, Control & Automation	Identify/select smart grid technologies to prototype/test with.	Test automation hardware & controllers. Invest in SCADA/SA	Pilot automation hardware, controllers & CVR.	Advance pilots to feeder and substation levels. Track grid impact. Determine costs/benefits.	
Information Technology	Select network modeling technologies.	Develop geospatial network/connectivity model.	Evaluate a master or distributed software suite for integrated Volt/Var & CVR management.	Procure/integrate/deploy a master or distributed system software for integrated VVO/CVR.	
Standards and Training	Evaluate standards for communications, control & security. Assess staff and training needs.	Develop training plan for staff on voltage management technologies. Train staff engineering analysis and network modeling tools.	Adopt / implement standards. Train technicians on voltage management and automation hardware.	Extend training as needed to distribution operating & engineering staff on master/distributed system software for integrated VVO/CVR .	

CVR: Conservation Voltage Reduction
DA: Distribution Automation
SA: Substation Automation
SCADA: Supervisory Control and Data Acquisition
VVO: Volt/VAR Optimization

Figure 35: Implementation Roadmap Summary - Electrical Vehicle Charging - Leader

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision				
	2011-2012	2013-2014	2015-2016	2017-2018	2019-2020
Planning	Refine engineering models for EV integration. Evaluate pilot results. Plan feeder-scale EV tests.	Measure impact of EV stations. Pilot dynamic rate & incentive program.	Analyze impact on feeders. Extend rate & incentive pilot.	Continue communication/education /enrollment of customers in pilot.	Refine engineering models to support near real-time analysis.
Communications Infrastructure	Invest in/expand DA/AMI telecommunications infrastructure & HAN deployments.				
Instrumentation, Control & Automation	Pilot net-metering technologies, advance protection & operation technologies for EV integration.	Assess pilot results. Expand SCADA & substation automation. Enable 3rd party EV charging stations.	Expand pilots to other substations & feeders. Track impact on grid.	Advance pilots to other substations & feeders. Determine costs/benefits.	Advance pilots to enable automated control of EV charging. Determine costs/benefits.
Information Technology	Refine geospatial connectivity model. Evaluate architecture options & integration needs for automated control and management of EV resources.	Procure/integrate/deploy a master or distributed software suite for advanced DER/EV control and integrated VVO/CVR management.	Conduct pilots for advanced control & management of EV charging/discharging stations for DR/DLC events.	Conduct pilots for integrated & automated voltage management for system reliability events.	Conduct real time engineering flow analysis to optimize system voltage and resources.
Standards and Training	Evaluate /adopt/implement standards for EV integration. Refine equipment selection. Identify needs & develop training. Train personnel on EV integration technologies.		Participate in standards advancement. Expand training.	Extend training for personnel for near real-time engineering analysis to enable dynamic management of EV resources. Reevaluate workforce needs.	

AMI: Advanced Metering Infrastructure
CVR: Conservation Voltage Reduction
DA: Distribution Automation
DER: Distributed Energy Resources
DLC: Direct Load Control
DR: Demand Response
EV: Electric Vehicle
HAN: Home-Area Network
SCADA: Supervisory Control and Data Acquisition
VVO: Volt/VAR Optimization

Figure 36: Implementation Roadmap Summary - Electrical Vehicle Charging - Follower

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision 2011-2012	2013-2014	2015-2016	2017-2018	2019-2020
Planning	Develop business case for EV integration to the grid.	Pilot rate & incentive programs for EV customers. Communicate/educate/enroll customers.	Extend pilot & incentive programs. Continue communication/education. Construct engineering models for pilots.	Extend pilots. Determine impact of EV charging station deployments on grid.	Plan system-wide deployment for EV.
Communications Infrastructure	Assess telecommunications infrastructure to support EV integration.	Procure/test communication system elements.	Pilot communication technologies.	Invest in/expand telecommunications infrastructure to support EV integration.	
Instrumentation, Control & Automation	Idenitfy/select metering and EV integration technologies to prototype/test with.	Invest in SCADA/SA. Deploy utility/3rd party charging stations. Test net-metering, power inverter technology, voltage sensors & controllers for EV integration.	Pilot net metering technologies, IHDs & power inverter technology for EV charging stations.	Advance pilots for drawing power from EV's battery for customer use & to enable automated control of EV charging status. Determine costs/benefits.	
Information Technology	Select network modeling technologies.	Develop geospatial network model.	Evaluate master/distributed software suite for DER, EV control systems & integrated Volt/VAR & CVR management.	Procure/deploy/test a master or distributed software suite for management of EV & VVO/CVR functionality.	
Standards and Training	Evaluate standards for communications, control & security. Assess staff and training needs.	Plan staff training for EV integration. Train staff on EV integration technologies and network modeling.	Adopt / implement standards. Train staff on EV integration technologies.	Extend training as needed to operating & engineering staff on EV integration and integrated VVO/CVR management technologies.	

CVR: Conservation Voltage Reduction
DER: Distributed Energy Resources
DR: Demand Response
EV: Electric Vehicle
IHDs: In-Home Displays
SA: Substation Automation
SCADA: Supervisory Control and Data Acquisition
VVO: Volt/VAR Optimization

Figure 37: Implementation Roadmap Summary - Asset Management - Leader

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision 2011-2012	2013-2014	2015-2016	2017-2018	2019-2020
Planning	Refine engineering models. Evaluate pilot results. Plan feeder-scale tests of asset monitoring and management technologies.	Conduct loading, loss, voltage/reliability and fault analysis for capital & expenditure plans.	Analyze impact on feeders and extend pilots.	Expand system-wide deployment of asset monitoring and management technologies based on pilot results.	Refine engineering models to support near real-time analysis & integrated resource planning.
Communications Infrastructure	Expand telecommunications infrastructure & reliability requirements to support asset monitoring & management.				
Instrumentation, Control & Automation	Pilot sensor technologies & predictive maintenance practices.	Assess pilot results. Expand SCADA & substation automation to support broader automation.	Expand pilots to other substations & feeders. Determine costs/benefits.	Advance pilots to other substations & feeders & asset classes. Determine costs/benefits.	
Information Technology	Refine geospatial connectivity model. Evaluate architecture options & integration needs for automated asset management with condition-/performance-based maintenance capability.	Procure / integrate / deploy a master or distributed condition-/performance-based maintenance solution.	Conduct pilots for advanced resource planning on select feeders/substations.	Integrate circuit reconfiguration & asset control & management.	Integrate real-time analysis with integrated resource planning.
Standards and Training	Evaluate /adopt/implement standards for proactive system planning. Refine equipment selection. Identify needs & develop training.		Participate in standards advancement. Expand training.	Extend training as needed to operating and engineering staff for integrated proactive system planning and management.	

SCADA: Supervisory Control and Data Acquisition

Figure 38: Implementation Roadmap Summary - Asset Management - Follower

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision				
	2011-2012	2013-2014	2015-2016	2017-2018	2019-2020
Planning	Develop business case for SA & DA.	Construct engineering models for pilots.	Refine engineering models based on pilots and develop implementation plans.	Conduct loading, loss, voltage/reliability, & fault analysis with EA to prepare expenditure plans.	Plan system-wide deployment of asset monitoring and management technologies for proactive system planning.
Communications Infrastructure	Assess telecommunications infrastructure to support asset monitoring & management.	Procure/test communication system elements.	Pilot communication technologies.	Invest in/expand telecommunications infrastructure to support asset monitoring & management.	
Instrumentation, Control & Automation	Idenitfy/select smart grid technologies to prototype/test with.	Test asset monitoring and sensor technologies. Invest in SCADA/SA	Pilot remote asset monitoring, visualization technologies & predictive maintenance practices.	Advance pilots to feeder and substation levels. Determine costs/benefits.	
Information Technology	Select network modeling technologies. Evaluate OMS & IVR capabilities.	Develop geospatial network model. Implement OMS & IVR.	Evaluate master/distributed software suite for asset management with condition-based maintanance capability.	Procure/deploy/test a master or distributed software suite for condition-based asset management and maintenance.	
Standards and Training	Evaluate standards for communications, control & security. Assess staff and training needs.	Plan staff training for asset management and planning. Train engineering staff on asset planning and modeling tools.	Adopt / implement standards. Train technicians on asset monitoring technologies.	Extend training as needed to operating and engineering staff on advanced asset management and planning tools.	

DA: Distribution Automation
EA: Engineering Analysis
IVR: Interactive Voice Response
OMS: Outage Management System
SA: Substation Automation
SCADA: Supervisory Control and Data Acquisition

Recurring Activities

Recurring Processes

Readers will notice certain patterns that repeat in the roadmaps. For example, the need for validated engineering models arises early in several processes, and communications infrastructure is a prerequisite for many Smart Grid use cases. The same words appear in each roadmap related to these recurring tasks.

Other recurring needs receive little attention in the roadmaps, but require and deserve significant effort. These include the business case, change management, and core IT functions that must be integrated with every new system and its related business processes.

Business Case

Long experience at SAIC and many other competent businesses has shown that creating a business case—first to plan, and later to manage a major project—establishes reference points that are essential for successfully navigating the uncertainties and changes that arise during the project. The business case discussed in Chapter 5 can be created and examined at any level of detail. Before embarking on a major Smart Grid investment, it is valuable to examine its business case at a top level to estimate the likely costs, benefits, and other project dimensions. If these are favorable, that finding justifies the further effort to create the business case in detail, which then enables detailed project planning.

The old maxim, "You can't manage what you don't measure" certainly is valid. Measurement is necessary to project management. But measurement is not sufficient. One must have meaningful benchmarks and reference points against which to compare the measured values. As the project proceeds, the business case that was created in advance provides those references, making it possible to assess accurately whether the project is producing the intended benefits at the predicted costs.

The future constantly surprises and frustrates diligent planners, and projects rarely proceed as planned. The business case also is the template against which project revisions are measured, providing confidence that the changes will sustain the original vision and intent, and allowing quantitative assessment of the cost and benefit consequences of the changes.

Therefore, although the Roadmaps do not show all the business case efforts, POUs should estimate the benefits, tally the costs, and assess the financial productivity of every major investment. The business case should be revisited regularly during the project—not less often than annually—and used to keep the project on track. The tools provided in Chapter 4 will serve well toward this goal.

Change Management

Greek philosopher Heraclitus (c.535 BC - 475 BC) is credited with declaring that, "Nothing endures but change." Managers at every level in every organization manage change all the time. The Roadmaps do not specifically include change management and business process revision, but it is essential for the utility to realize the full benefit of Smart Grid investments.

Consider this example: A utility deploys automated meter reading. The only business process changes implemented are to eliminate manual reading and integrate the data flow from the meter reading system with the billing system. This achieves a major benefit in reduced meter reading cost, and the benefit is fully realized when the former meter readers are reassigned, retired, or otherwise become productive in other functions. That will be all the benefit if nothing further is done. If the billing process altered to send the bills immediately after the readings arrive, instead of waiting for a manual route to be completed, the additional benefit of advancing all of the utility's future cash flow by a few days will be realized. If a new business process is created to gather voltage data, identify underperforming distribution segments, upgrade them, and then adjust the feeder voltage down slightly, a large efficiency benefit in reduced losses will be realized. If IT work is done to make meter data accessible to call center operators, and if their processes are revised to exploit those data, many calls will be resolved in a shorter time, producing another efficiency benefit as well as increasing customer satisfaction.

And there are many more; the list goes on and on. A large fraction of Smart Grid benefits require business process changes. Not shown in most of the roadmaps because it belongs nearly everywhere, business process analysis and revision is a basic management function. In a Smart Grid deployment, this function must be prosecuted more intensively than normal to garner the full benefits of technology deployments. Several analytical approaches to process analysis and revision are widely used. These are the subject of many competent books, and of high-value consulting support to utilities.

Core IT Functions

Central IT functions must be addressed and integrated with every new automation system and its associated business processes. Examples include:

- Backup
- Disaster recovery
- Cyber security

These and other, similarly basic IT functions are not described in the POU Roadmaps because their recurring duplication will clutter the main themes. But POUs must remember and include them in project planning and execution. The SGMM roadmap includes them at a top level as a structural reminder.

Backup

Every business organization relies crucially on its IT resources, and therefore has a thoughtfully detailed plan for backing up those resources to protect against document corruption, hard drive failure, and other technical malfunctions. As new automation systems are introduced, the backup plan must be expanded to include the new resources, and backups must begin immediately as the resources are deployed.

Disaster Recovery

As with backup, every well-run organization has a plan for recovering its IT resources after a fire, earthquake, flood, terrorist incident, sabotage, or other major disaster destroys some or all those resources. The disaster recovery plan often involves having a second operating location from which the utility's essential functions can be conducted, which has ready access to the backups, and which can be brought on line quickly when needed.

Implementation of each new automation system must be consistent with the utility's disaster recovery approach, and it must be encompassed within that approach as it is deployed.

Cyber Security

Failure to adequately secure IT resources and data communications invites trouble on a scale that is hard to overstate. Security researchers report that an unprotected computer connected to the internet becomes compromised within minutes by malware that can secretly and silently employ that computer for criminal purposes in other parts of the world or, perhaps worse, create extensive damage within the local IT environment. In an operating utility where Smart Grid resources manage lethal voltages and support the regional economy, this can result in major economic and personal hazards.

Plainly, cyber security is a function that must attend every Smart Grid project from planning through implementation and operation.

Core IT Conclusion

The very first Initiating level of the Technology domain of the Smart Grid Maturity Model requires that a utility establish an enterprise IT architecture that will align Smart Grid implementation with IT resources. The enterprise architecture will address a full and versatile security framework, comprehensive backup, and a disaster recovery approach. These core IT functions must support every Smart Grid pursuit.

The POU Roadmaps do not specify all the detailed steps for these functions because the steps would be repetitive and would encumber, perhaps even obscure, the main technology threads of Smart Grid work. But they are essential and must be included. POUs can rely on the organized detail of the SGMM for these functions.

Table 29: Substation Automation Implementation Roadmap - Leaders

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision					CA POU 2020 Smart Grid Vision
	2011-12	2013-14	2015-16	2017-18	2019-20	
Planning	Adjust Implementation/ Deployment Plans with consideration for integrated protection and control based on results of pilots. Identify scope and location of feeder scale deployments.		Adjust plans based on results of feeder level deployments. Prioritize system wide deployment for desired effect.			
	Construct and refine engineering models and analysis tools for pilots.	Conduct reliability analysis with engineering analysis tool(s)/application(s) to design feeder deployments and determine settings for proper protective coordination under normal operating, maintenance, outage-induced reconfigurations, and emergency conditions such as transient and inclement weather.		Refine engineering models/analysis as needed for near real-time dynamic analysis and operation of protective elements in the field including management of DERs using real-time status information		Improve system planning and management for reliability, and reduce capital, maintenance, and operating expense.
Communications Infrastructure	As needed, expand telecommunications infrastructure (fiber optic, wireless, copper …) to meet latency, bandwidth, frequency, and reliability requirements to support proper protection and control operations with consideration for terrain, coverage, security, and cost					
Instrumentation, Control & Automation	As needed, expand SCADA and substation automation to substations and circuits					
	Conduct controlled pilots with microprocessor-based relay and recloser controls with ability to alter relay settings groups for basic system protection and control functionality through SCADA and analysis on select substation(s)/feeder(s)	Advance pilots to other substations and feeders. Prioritize for desired impact. Measure and test results to determine costs/benefits.				Improve system reliability and monitoring
	Conduct controlled pilots for coordinated protection and control through SCADA by remotely altering relay settings groups and protective elements	Advance pilots to other substations and feeders. Prioritize for desired impact. Measure and test results to determine costs/benefits.				Maximize asset life, reduce outage duration and the number of sustained outages, improve customer satisfaction, and reduce economic losses
	Conduct controlled pilots with advanced protection and operation technologies (such as Low Voltage ride-through (LVRT) and anti-islanding) that manage bi-directional power flow in distribution circuits for distributed energy resources (DER) (such as renewables, storage, PV) integration on select feeder(s)/substation(s)		Advance pilots to other substations and feeders. Prioritize for desired impact. Measure and test results to determine costs/benefits in conjunction with distributed generation, storage, and electric vehicle charging.			Improve integration and control of DER for grid reliability, stability and efficiency.
Information Technology	Construct/refine geospatial network model with asset connectivity and asset data. Integrate GIS (asset information), CIS (customer information) and EA (asset specifications & connectivity) for a complete view of network model	Update geospatial network model per new deployments and system configurations, and advance integration effectiveness				

Table 29: Substation Automation Implementation Roadmap - Leaders

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision					CA POU 2020 Smart Grid Vision
	2011-12	2013-14	2015-16	2017-18	2019-20	
	Implement Outage Management System (OMS) and Interactive Voice Response (IVR) system if needed. Integrate OMS (outage information) with GIS/CIS and SCADA to provide a complete view of outage and system status information	**Advance integration effectiveness**				
Information Technology (continued)	Evaluate master or distributed system software that is embedded in system devices and can be used for autonomous protection and control capability. Evaluate system integration needs especially with SCADA, GIS, OMS, CIS, DMS, AMI/MDMS, EA and EMS and define requirements	Procure, deploy and test a master or distributed system software (SCADA/DMS/3rd party application/firmware that is embedded in system devices for autonomous functionality) and integrate with SCADA, DMS, OMS/GIS, AMI/MDMS, Distributed Energy Resource (DER) control systems, Energy Management Systems (if available), and engineering analysis tools/applications for integrated/coordinated protection and control functionality. Potential value from interface with weather systems that predict inclement weather	Conduct controlled pilots for dynamic and coordinated protection and control of protective elements using actual and more granular operational and condition/status data from system assets for near real-time reliability analysis on select feeder(s)/substation(s) and advance integration effectiveness	Using state estimator and real-time load flow analysis applications, monitor system parameters and microprocessor-based relays, reclosers and other protective elements statuses and dynamically program/control protective elements in coordination including the control and management of DER technologies through DMS. Enable automation/control by design by integrating circuit reconfiguration and protective device control and management functionalities through master DMS station to prevent and mitigate safety, reliability and stability risks before they happen in near real-time.		Maximize asset life, and reduce outage duration and the number of sustained outages, improve customer satisfaction, and reduce economic losses. Improve integration and control of DER for grid reliability, stability and efficiency. Thus reduce GHG emissions
Standards	Evaluate, adopt and implement standards (communications, interoperability, cyber security…) for integrated protection and control monitoring and management as needed around the preferred technologies/vendors that will underlie future Smart Grid implementations. Refine equipment selections in preparation for feeder scale deployment		Actively participate in advancement and extension of standards			
Training	Identify and develop training requirements with emphasis on field, engineering and operating personnel. Train SCADA technicians on programming the relays, and recloser controls, RTUs and other hardware components	Revise training as needed by evolution of standards and choices of equipment and systems. Train distribution engineers on downloading/exporting historical operational and performance data for advanced reliability analysis and trending applications	Advance extent and depth of training as technological complexity increase with scale of deployment. Train distribution engineers on advanced engineering analysis applications/solutions for near real-time reliability analysis and protection coordination. Reevaluate workforce needs.	Advance extent and depth of training for distribution engineers for state estimator and real-time engineering analysis tools/applications enabling dynamic management and control of system protective elements configuration and settings. Reevaluate workforce needs.		Improve acceptance, safety, efficiency and reliability

Table 30: Substation Automation Implementation Roadmap - Followers

Strategic Focus Areas	**Key Milestones to Achieve 2020 Smart Grid Vision**					**CA POU 2020 Smart Grid Vision**
	2011-12	**2013-14**	**2015-16**	**2017-18**	**2019-20**	
Planning	Develop a business case for SA and DA with consideration for integrated protection and control for reliability		Develop Implementation/ Deployment Plans based on results of pilots. Identify scope and location of feeder scale deployments.		Adjust plans based on results of feeder level deployments. Prioritize system wide deployment for desired effect.	
			Construct and refine engineering models and analysis tools for pilots.	Conduct reliability analysis with engineering analysis tool(s)/application(s) to design feeder deployments and determine settings for proper protective coordination under normal operating, maintenance, outage-induced reconfigurations, and emergency conditions such as transient and inclement weather.		Improve system planning and management for reliability, and reduce capital, maintenance, and operating expenditures
Communications Infrastructure	Assess telecommunications infrastructure needs to support asset monitoring and management operations	Identify, procure & test communication system elements	Conduct controlled pilots of communication technologies with consideration for terrain, coverage, security, reliability, latency and cost	Invest in/expand telecommunications infrastructure (fiber optic, wireless, copper …) to meet latency, bandwidth, frequency, and reliability requirements to support proper protection and control operations with consideration for terrain, coverage, security, and cost		
Instrumentation, Control & Automation	Assess existing SA and DA capabilities	Invest in/expand SCADA and substation automation to substations and circuits				
	Identify/select Smart Grid technologies to prototype/ test with	Conduct prototyping/testing of microprocessor-based relay and recloser controls with ability to alter relay settings groups	Conduct controlled pilots for basic system protection and control functionality through SCADA and analysis on select substation(s)/ feeder(s)	Advance pilots to other substations and feeders. Prioritize for desired impact. Measure and test results to determine costs/benefits.		Improve system reliability and monitoring
			Conduct controlled pilots for coordinated protection and control through SCADA by remotely altering relay settings groups and protective elements	Advance pilots to other substations and feeders. Prioritize for desired impact. Measure and test results to determine costs/benefits.		Extend asset life, reduce outage duration and the number of sustained outages, improve customer satisfaction, and reduce economic losses
Information Technology	Identify/select network modeling technologies/ applications (GIS, engineering analysis (EA))	Develop geospatial network model with asset connectivity and asset data.	Integrate GIS (asset information), CIS (customer information) and EA (asset specifications and connectivity) for a complete view of network model.	Update geospatial network model per new deployments and system configurations, and advance integration effectiveness		
	Evaluate and implement Outage Management System (OMS) and Interactive Voice Response (IVR-if needed) system and integrate these two systems		Integrate OMS (outage information) with GIS/CIS and SCADA to provide a complete view of outage and system status information	Advance integration effectiveness		

Table 30: Substation Automation Implementation Roadmap - Followers

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision					CA POU 2020 Smart Grid Vision
	2011-12	2013-14	2015-16	2017-18	2019-20	
Information Technology (continued)			Evaluate master or distributed system software that is embedded in system devices and can be used for autonomous protection and control capability	Procure, deploy and test a master or distributed system software (SCADA/DMS/3rd party application/firmware that is embedded in system devices for autonomous functionality) and integrate with SCADA, OMS/GIS, and engineering analysis tools for integrated protection and control functionality.		Extend asset life, reduce outage duration and the number of sustained outages, improve customer satisfaction, and reduce economic losses
Standards	Research and evaluate standards for communications, control and security		Adopt and implement standards (communications, interoperability, cyber security…) for integrated protection and control monitoring and management as needed around the preferred technologies/vendors that will underlie future Smart Grid implementations. Refine equipment selections in preparation for feeder scale deployment			
Training	Assess staffing and training needs	Identify and develop training requirements with emphasis on field, engineering and operating personnel.	Train SCADA technicians on programming the relays, and recloser controls, RTUs and other hardware components and distribution engineers on reliability analysis tools and modeling	Revise training as needed by evolution of standards and choices of equipment and systems. Train distribution engineers on reliability analysis applications/solutions for placement and determination of settings of protective elements for proper protective coordination. Reevaluate workforce needs.		Improve acceptance, safety, efficiency and reliability

Table 31: Advanced Metering and Demand Response Implementation Roadmap - Leaders

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision					CA POU 2020 Smart Grid Vision
	2011-12	2013-14	2015-16	2017-18	2019-20	
Planning	Adjust implementation/deployment plans for AMI, demand response (DR), load control, and combined demand management. Confirm scope and location of system level deployments.					
Planning	Communicate and educate customers on existing & emerging rate & incentive programs. Enroll customers in these programs for pilots. Track results & modify programs for maximum effect.		Extend dynamic rate programs and incentive programs for all customers. Communicate and educate customers on these programs. Enroll customers to these programs.		Evaluate customer programs results vis-à-vis revenue requirements. Revise as needed.	
Communications Infrastructure	Execute/expand telecommunications infrastructure (fiber optic, wireless, copper …) to meet latency, bandwidth, frequency, and reliability requirements to support advanced metering & load management, with consideration for terrain, coverage, security, and cost.		Execute/expand Home-Area-Network (HAN) deployments to support advanced DR/ load control.	Enhance telecomm to support customer appliance communication.		
Instrumentation, Control & Automation	Complete system-wide deployment of two-way metering and related technologies.					Improve revenue cycle process.
Instrumentation, Control & Automation	Extend pilot rate & incentive customers programs to encourage reducing/ shedding load during emergency, peak-hours when required by the utility and/or the regional authorities (such as CPP, time variant rates, ... and so forth.). Continue controlled pilots with dynamic rate programs (TOU, CPP, and so forth.) for DR, & load management in selected customer groups.		Expand pilots to include IHDs / HANs and DR, and measure changes in load/ demand in response to DR and utility events. Prioritize for desired impact. Measure and test results to determine costs/benefits.		Begin pilot tests of direct utility/ meter interaction with "smart" customer appliances.	Reduce customer consumption and peak demand.
Information Technology	Upgrade/ replace the CIS with consideration for integration with MDMS, customer web portals, demand response, load management systems, and other utility systems as needed.					
Information Technology	Procure, deploy and test AMI Head-end system for advanced two-way metering. Integrate AMI Head-end system with MDMS, demand response/management systems and direct load control systems. Potential value from integration with SCADA, and OMS.	Integrate AMI Head-end system with master demand response/ management systems and direct load control systems, DMS, DER control systems, and EMS. Advance integration effectiveness.				Improve meter reading accuracy. Reduce billing cycles and errors.
Information Technology	Procure, deploy and test MDMS solution for handling meter reading data. Integrate MDMS with AMI, CIS, demand response/management systems, direct load control systems and customer web portal solutions. Potential value from integration with SCADA, OMS and DA systems.	Integrate MDMS with master demand response/ management systems and direct load control systems, DMS, DER control systems, and EMS. Advance integration effectiveness.				Improve meter reading data handling, availability and accuracy for other systems and various uses.

Table 31: Advanced Metering and Demand Response Implementation Roadmap - Leaders

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision 2011-12	2013-14	2015-16	2017-18	2019-20	CA POU 2020 Smart Grid Vision
Information Technology (continued)	Procure, deploy and test a customer web portal solution and offer extended services. Enable customers to have a more granular view of their load profiles, learn about different rate programs, DR/demand management programs, request service connect/disconnect, pay bills, and so forth. Integrate customer web portal with MDMS & CIS, and with OMS for presenting outage information.	Offer extended Web portal services, allowing customers to compare their savings under different rate programs given their load profiles, enroll in different rate programs, opt-in and out of DR/load control and management events, set their preferences for DR/load control and management events, and so forth. Integrate the web portal with demand response/ management systems, direct load control systems, Home Energy Management Systems for management and control of customer device(s)/ appliance(s) through HANs. Advance integration effectiveness.				Enable customer empowerment, improve customer participation.
	Evaluate master or distributed system software for Demand Response/ Management/Direct Load Control systems. Evaluate system integration needs especially with MDMS and AMI for management and control of customer device(s)/ appliance(s) through HANs, DMS, DER control systems, and EMS, and define requirements.	Procure, deploy and test a software system for demand response/load control and management. Integrate the system with MDMS, AMI for management and control of customer device(s)/ appliance(s) through HANs, DMS, DER control systems, and EMS.	Conduct controlled pilots for integrated and automated DR/load control and management of all DR, DG, and DER resources through master station to optimize resource utilizations and system reliability on select feeder(s)/ substation(s).	Conduct real-time analysis to optimize and control all DER (storage, PEV), DG, and DR resources through the master station in an integrated and automated fashion in response to DR/load control/management, and system reliability events.		Maximize control/ management of all resources including DR, DG, DER, customer devices in an integrated fashion, reduce consumption & peak demand. Reduce energy and demand charges. Reduce carbon footprint, GHG emissions.
Standards	Evaluate, adopt and implement standards (communications, interoperability, cyber security…) for advanced metering and DR/load control and management related technologies as needed around the preferred technologies/vendors that will underlie future Smart Grid implementations. Refine equipment selections in preparation for feeder scale deployment.		Actively participate in advancement and extension of standards.			
Training	Identify and develop training requirements with emphasis on field, engineering and operating personnel. Train field personnel on advanced metering and communication technologies. Train operations personnel on AMI, MDMS, customer web portal, and their interactions with one another. Train customer service personnel on advanced services (rate programs, DR/load control and management programs) through customer web portals.	Revise training as needed by evolution of standards and choices of equipment and systems. Train operations personnel on demand response/management/direct load control solutions and its interactions with other systems. Train customer service personnel on advanced services through customer web portals.	Advance extent and depth of training as technological complexity increase with scale of deployment. Train distribution operators/engineers on advanced analysis applications/solutions for advanced system reliability and resource planning. Reevaluate workforce needs.	Advance extent and depth of training for distribution operators/engineers for near real-time engineering analysis tools/applications enabling dynamic management and control of all DR, DG, and DER resources, system configurations and assets. Reevaluate workforce needs.		Improve acceptance, safety, efficiency and reliability.

Table 32: Advanced Metering and Demand Response Implementation Roadmap - Followers

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision					CA POU 2020 Smart Grid Vision
	2011-12	2013-14	2015-16	2017-18	2019-20	
Planning	Develop a business case for AMI and demand response / load control solutions		Develop Implementation/ Deployment Plans based on results of pilots. Identify scope and location of feeder scale deployments.		Adjust plans based on results of feeder level deployments and prioritize system wide deployment for desired effect	
	Develop pilot rate and incentive programs for customers to reduce peak demand and consumption. Communicate and educate customers on these programs. Enroll customers to these programs for pilots		Develop/extend pilot rate and incentive programs for customers to encourage reducing/shedding load during emergency, peak-hours when required by the utility and/or the regional authorities (such as Critical Peak Pricing (CPP), time variant rates,...and so forth.). Communicate and educate customers on these programs. Enroll customers to these programs for pilots			
Communications Infrastructure	Assess telecommunications infrastructure needs to support advanced two-way metering	Identify, procure & test two-way communication system elements (AMI/HAN)	Conduct controlled pilots with AMI and HAN communication technologies with consideration for terrain, coverage, security, reliability, latency and cost	Invest in/expand telecommunications infrastructure (fiber optic, wireless, copper …) to meet latency, bandwidth, frequency, and reliability requirements to support AMI and demand response/management operations with consideration for terrain, coverage, security, and cost		
Instrumentation, Control & Automation	Identify/select two-way metering technologies to prototype/ test with	Conduct prototyping/testing of two-way metering systems	Conduct controlled pilots with two-way metering systems on select feeder(s)/substation(s)	Advance pilots to feeder and then substation area deployments. Prioritize for desired impact. Measure and test results to determine costs/benefits.		Improve meter reading process
	Identify/select In-Home Displays (IHD), Home Area Network (HAN) technologies to prototype/ test with	Conduct prototyping/testing of HANs/IHDs for DR, demand/load management	Conduct controlled pilots with dynamic rate programs (TOU, CPP,…and so forth) for DR, demand/load management on select feeder(s)/substation(s)	Advance pilots to feeder and then substation area deployments and measure changes in load/demand in response to DR and load management events. Prioritize for desired impact. Measure and test results to determine costs/benefits.		Reduce customer consumption and peak demand
	Identify/select direct load control devices/appliances to prototype/test with	Conduct prototyping/testing of direct load control devices/appliances for direct load control and demand/load management.	Conduct controlled pilots with dynamic rate programs (TOU, CPP,…and so forth) and direct load control devices/appliances for direct load control and demand/load management on select feeder(s)/substation(s)	Advance pilots to feeder and then substation area deployments and measure changes in load/demand in response to direct load control, DR and load management events. Prioritize for desired impact. Measure and test results to determine costs/benefits.		Reduce customer consumption and peak demand
Information Technology	Evaluate CIS integration capabilities and determine if it needs to be upgraded or replaced	If needed, upgrade/replace the CIS system with consideration for integration with MDMS, customer web portals, demand response/management systems and other utility systems as needed				
			Evaluate AMI Head-end system for advanced two-way metering. Evaluate system integration needs especially with MDMS, demand response/management systems and direct load control systems, and define requirements. Potential value from integration with SCADA, OMS and DA systems.	Procure, deploy and test AMI Head-end system for advanced two-way metering. Integrate AMI Head-end system with MDMS, demand response/management systems and direct load control systems. Potential value from integration with SCADA, OMS and DA systems.		Improve meter reading accuracy. Reduce billing cycles and errors.

Table 32: Advanced Metering and Demand Response Implementation Roadmap - Followers

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision					CA POU 2020 Smart Grid Vision
	2011-12	2013-14	2015-16	2017-18	2019-20	
Information Technology (continued)			Evaluate MDMS solutions for handling meter reading data. Evaluate system integration needs especially with AMI, CIS, demand response/management systems, direct load control systems and customer web portal solutions, and define requirements. Potential value from integration with SCADA, OMS and DA systems.	Procure, deploy and test MDMS solution for handling meter reading data. Integrate MDMS with AMI, CIS, demand response/management systems, direct load control systems and customer web portal solutions.		Improve meter reading data handling, availability and accuracy for other systems and various uses.
			Evaluate master or distributed solution for customer web portal. Evaluate system integration needs especially with MDMS, CIS, demand response/ management systems, direct load control systems, Home Energy Management Systems and define requirements.	Procure, deploy and test a master or distributed solution for customer web portal. Enable customers to have a more granular view of their load profiles and offer extended services (educate themselves on different rate programs, DR/demand management programs; request service connect/disconnect, pay bills, and... and so forth.). Integrate customer web portal with MDMS and CIS. Potential value from integrating with OMS for presenting outage information.		Enable customer empowerment, improve customer participation
			Evaluate master or distributed system software for Demand Response/ Management/Direct Load Control systems. Evaluate system integration needs especially with MDMS and AMI for management and control of customer device(s)/ appliance(s) through HANs, and define requirements.	Procure, deploy and test a master or distributed system software for demand response/load control and management. Integrate master or distributed system software with MDMS, AMI for management and control of customer device(s)/ appliance(s) through HANs.		Improve control and management of customer devices, consumption and peak demand. Reduce energy and demand charges
Standards	Research and evaluate standards for communications, control and security		Adopt and implement standards (communications, interoperability, cyber security…) as needed around the preferred technologies/vendors that will underlie future Smart Grid implementations. Refine equipment selections in preparation for feeder scale deployment			
Training	Assess staffing and training needs.	Identify and develop training requirements with emphasis on field, engineering and operating personnel.	Train field personnel on advanced metering and communication technologies. Train operations personnel on AMI, MDMS, customer web portal, demand response/management/direct load control solutions and their interactions with one another. Train customer service personnel on advanced services (rate programs, DR/load control and management programs) through customer web portals.	Revise training as needed by evolution of standards and choices of equipment, systems and DR/load control and management programs. Train operations personnel on AMI, MDMS, customer web portal, demand response/ management/direct load control solutions and their interactions with one another. Reevaluate workforce needs.		Improve acceptance, safety, efficiency and reliability

Table 33: Distributed Energy Resources Implementation Roadmap - Leaders

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision					CA POU 2020 Smart Grid Vision
	2011-12	2013-14	2015-16	2017-18	2019-20	
Planning	Adjust Implementation/ Deployment Plans for distributed energy resources (DER) and distributed generation (DG) integration to the grid based on results of pilots. Identify scope and location of feeder-scale deployments.		Adjust plans based on results of feeder level deployments and prioritize system wide deployment for desired effect.			
	Develop/extend pilot dynamic rate and incentive programs (such as Critical Peak Pricing (CPP), time variant rates, and so forth.) for DER/DG customers including feed-in tariffs for selling excess generation back to the utility. Communicate and educate customers on these programs. Enroll customers to these programs for pilots.		Extend dynamic rate programs and incentive programs for all DER/DG customers to encourage them to turn on their DER/DG during emergency, peak-hours when required by the utility and/or the regional authorities. Communicate and educate customers on these programs. Enroll customers to these programs.			
	Construct and refine engineering models for DER/DG integration pilots.	Conduct engineering analysis to determine the impact of DER/DG deployments on the grid, and to better prepare capital and operation expenditure plans focusing on the right areas for system improvement, maintenance and expansion.		Refine engineering models/analysis as needed for near real-time analysis, integrated resource planning including dynamic and optimized planning and management of DERs.		Improve system planning for DER/DG integration and management
Communications Infrastructure	Invest in/expand DA/AMI telecommunications infrastructure (fiber optic, wireless, copper …) to meet latency, bandwidth, frequency, and reliability requirements to support DER/DG integration and management operations with consideration for terrain, coverage, security, and cost. Invest in /expand Home-Area-Network (HAN) deployments in order to support advanced DER/DG control and management functions for demand response (DR), direct load control and system reliability.					
Instrumentation, Control & Automation	As needed, expand SCADA and substation automation to substations and circuits					
	Conduct controlled pilots with net-metering technologies and dynamic rate programs including feed-in tariffs for selling excess generation back to the utility. Monitor and measure DER/DG customers' load profiles and changes due to on-site DER/DG generation on select feeder(s)/substation(s). Conduct controlled pilots with in-home displays (IHDs) to communicate on-site DER/DG status, generation information, market information, and DR/direct load control events to the customers.		Advance pilots to feeder and then substation area deployments. Monitor, measure and control impact on the grid. Prioritize for desired impact. Measure and test results to determine costs/benefits.			Reduce dependence on conventional generation resources, and reduce energy and demand charges
	Conduct controlled pilots with advanced protection and operation technologies (such as Low Voltage ride-through (LVRT) and anti-islanding) that manage bi-directional power flow in distribution circuits for distributed energy resources (DER) (such as renewables, storage, PV) integration on select feeder(s)/substation(s)		Advance pilots to other substations and feeders. Prioritize for desired impact. Measure and test results to determine costs/benefits in conjunction with distributed generation and storage.			Improve integration and control of DER/DG for grid reliability, stability and efficiency.
	Conduct controlled pilots with controllable power inverter technology, voltage sensors/regulators and controllers for distributed energy resources (renewables, storage, PV) integration and voltage regulation by monitoring and remotely controlling DER/DG power inverters, voltage regulators and controllers through SCADA on select feeder(s)/substation(s)	Advance pilots to enable automated control of DER/DG in response to demand response (DR), system reliability events. Advance pilots to feeder and then substation area deployments. Prioritize for desired impact. Measure and test results to determine costs/benefits in conjunction with DR and system reliability activities.				Improve integration and control of DER/DG for grid reliability, stability and efficiency.

Table 33: Distributed Energy Resources Implementation Roadmap - Leaders

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision					CA POU 2020 Smart Grid Vision
	2011-12	**2013-14**	**2015-16**	**2017-18**	**2019-20**	
Information Technology	Construct and refine geospatial network model with asset connectivity and asset data. Integrate GIS (asset information), CIS (customer information) and EA (asset specifications and connectivity) for a complete view of network model.	Update geospatial network model per new DER/DG deployments and related technologies, and advance integration effectiveness.				
	Evaluate master or distributed system software for Distributed Energy Resource (DER) control systems and/or Energy Management Systems. Evaluate system integration needs especially with SCADA, DMS, AMI/MDMS, GIS, and engineering analysis (EA) tools/applications and define requirements.	Procure, deploy and test a master or distributed system software for control and management of DER/DG. Integrate master or distributed system software with SCADA, DMS, AMI/MDMS, GIS, and EA tools/ applications.	Conduct controlled pilots for advanced control and management of DER/DG through master or distributed system software in response to DR/ direct load control events on select feeder(s)/ substation(s) and advance integration effectiveness.	Conduct real-time engineering flow analysis to optimize and control of DER/DG through master station in an automated fashion in response to demand response (DR), direct load control and system reliability events.		Improve control and management of DER/DG for DR purposes. Reduce energy consumption and demand.
	Evaluate master or distributed system software for integrated Volt/VAr and CVR management and autonomous functionality. Evaluate system integration needs especially with SCADA, GIS, OMS, DMS, AMI/MDMS, EA and EMS and define requirements.	Procure, deploy and test a master or distributed system software (SCADA/DMS/3rd party) for integrated VVO/CVR functionality. Integrate master or distributed system software with AMI/MDMS, Distributed Energy Resource (DER) control systems, Energy Management Systems (if available), OMS/GIS and engineering analysis tools/ applications (if needed).	Conduct controlled pilots for integrated and automated voltage management through master or distributed system software (SCADA/DMS/3rd party) to optimize voltage on select feeder(s)/ substation(s) and advance integration effectiveness.	Conduct real-time engineering flow analysis to optimize and control system voltage/CVR through master station in an automated fashion including the control of DER/DG technologies in response to system reliability events.		Reduce GHG emissions and environmental footprint.
Standards	Evaluate, adopt and implement standards (communications, interoperability, cyber security…) for DER/DG integration related technologies and management and control of these resources for system reliability, DR and direct load control events as needed around the preferred technologies/vendors that will underlie future Smart Grid implementations. Refine equipment selections in preparation for feeder scale deployment.		Actively participate in advancement and extension of standards.			

Table 33: Distributed Energy Resources Implementation Roadmap - Leaders

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision					CA POU 2020 Smart Grid Vision
	2011-12	**2013-14**	**2015-16**	**2017-18**	**2019-20**	
Training	Identify and develop training requirements with emphasis on field, engineering and operating personnel. Train SCADA technicians on programming the relays, and recloser controls, RTUs and other hardware components. Train field personnel on net-metering technologies. Train distribution engineers on engineering analysis tools and network modeling	Revise training as needed by evolution of standards and choices of equipment and systems. Train distribution engineers on downloading/ exporting historical operational and performance data for advanced engineering analysis and trending applications. Train distribution operators on integrated master station software. Reevaluate workforce needs.	Advance extent and depth of training as technological complexity increase with scale of deployment. Train distribution engineers on advanced engineering analysis applications/solutions for advanced system reliability and resource planning. Reevaluate workforce needs.	Advance extent and depth of training for distribution engineers for near real-time engineering analysis tools/applications enabling dynamic management and control of DER/DG technologies, system configurations and assets. Reevaluate workforce needs.		Improve acceptance, safety, efficiency and reliability

Table 34: Distributed Energy Resources Implementation Roadmap - Followers

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision					CA POU 2020 Smart Grid Vision
	2011-12	2013-14	2015-16	2017-18	2019-20	
Planning	Develop a business case for distributed energy resources (DER) and distributed generation(DG) integration to the grid		Develop Implementation/ Deployment Plans based on results of pilots. Identify scope and location of feeder scale deployments.		Adjust plans based on results of feeder level deployments and prioritize system wide deployment for desired effect	
	Develop pilot rate and incentive programs for DER/DG customers. Communicate and educate customers on these programs. Enroll customers to these programs for pilots		Extend pilot rate and incentive programs for DER/DG customers including feed-in tariffs for selling excess generation back to the utility. Communicate and educate customers on these programs. Enroll customers to these programs for pilots			
			Construct and refine engineering models for DER/DG integration pilots	Conduct engineering analysis to determine the impact of DER/DG deployments on the grid and to better prepare capital and operation expenditure plans focusing on the right areas for system improvement, maintenance and expansion		Improve system planning for DER/DG integration
Communications Infrastructure	Assess telecommunications infrastructure needs to support DER/DG integration and management	Identify, procure & test communication system elements (AMI, DA)	Conduct controlled pilots of communication technologies (AMI, DA) with consideration for terrain, coverage, security, reliability, latency and cost	Invest in/expand telecommunications infrastructure (fiber optic, wireless, copper …) to meet latency, bandwidth, frequency, and reliability requirements to support DER/DG integration and management operations with consideration for terrain, coverage, security, and cost		
Instrumentation, Control & Automation	Assess existing SCADA and SA capabilities	Invest in/expand SCADA and substation automation to substations and circuits				
	Identify/select metering technologies to pilot with. Procure, deploy and test advanced metering technologies with net-metering capability for DER/DG customers.	Conduct controlled pilots with net-metering technologies to monitor and measure DER/DG customers' load profiles and changes due to on-site DER/DG generation on select feeder(s)/substation(s). Conduct controlled pilots with in-home displays (IHDs) to present on-site DER/DG status and generation information to the customer.		Advance pilots with feed-in tariffs for selling excess generation back to the utility. Monitor, measure, and control impact on the grid. Advance pilots to feeder and then substation area deployments. Prioritize for desired impact. Measure and test results to determine costs/benefits.		Reduce dependence on conventional generation resources, and reduce energy and demand charges
	Identify/select DER/DG technologies to prototype/ test with	Conduct prototyping/testing of controllable power inverter technology, voltage sensors/regulators and controllers for distributed energy resources (renewables, storage) integration	Conduct controlled pilots with controllable power inverter technology for distributed energy resources (renewables, storage, PV) integration and voltage regulation by monitoring and remotely controlling DER/DG power inverters, voltage regulators and controllers through SCADA on select feeder(s)/substation(s)	Advance pilots to enable automated control of DER/DG in response to demand response (DR), system reliability events. Advance pilots to feeder and then substation area deployments. Prioritize for desired impact. Measure and test results to determine costs/benefits in conjunction with DR and system reliability activities.		Integrate and control DER/DG for grid reliability, stability and efficiency
Information Technology	Identify/select network modeling technologies/ applications (GIS, engineering analysis (EA))	Develop geospatial network model with asset and connectivity data for a complete view of network model.		Update geospatial network model per new DER/DG deployments and related technologies, and advance integration effectiveness		

Table 34: Distributed Energy Resources Implementation Roadmap - Followers

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision					CA POU 2020 Smart Grid Vision
	2011-12	2013-14	2015-16	2017-18	2019-20	
Information Technology (continued)			Evaluate master or distributed system software for Distributed Energy Resource (DER) control systems and/or Energy Management Systems. Evaluate system integration needs especially with SCADA, GIS, and engineering analysis (EA) tools/applications and define requirements	Procure, deploy and test a master or distributed system software for control and management of DER/DG. Integrate master or distributed system software with SCADA, advanced metering systems, GIS, and EA tools/ applications		Improve control and management of DER/DG for DR purposes. Reduce energy consumption and demand.
			Evaluate master or distributed system software for integrated Volt/VAr and CVR management and autonomous functionality. Evaluate system integration needs especially with SCADA, GIS, and EA and define requirements	Procure, deploy and test a master or distributed system software (SCADA/DMS/3rd party) for integrated VVO/CVR functionality. Integrate master or distributed system software with OMS/GIS and engineering analysis tools/ applications		Reduce GHG emissions and environmental footprint
Standards	Research and evaluate standards for communications, control and security		Adopt and implement standards (communications, interoperability, cyber security …) as needed around the preferred technologies/vendors that will underlie future Smart Grid implementations. Refine equipment selections in preparation for feeder scale deployment			
Training	Assess staffing and training needs.	Identify and develop training requirements with emphasis on field, engineering and operating personnel. Train field personnel on net-metering technologies. Train distribution engineers on engineering analysis tools and network modeling	Train SCADA technicians on controllers, RTUs and other hardware components. Train field personnel on power inverter technologies for integration of distributed energy resources. Train engineering personnel on advanced engineering analysis for DER/DG integration	Revise training as needed by evolution of standards and choices of equipment and systems. Train distribution operators on integrated master station software. Reevaluate workforce needs.		Improve acceptance, safety, efficiency and reliability

Table 35: Distribution Automation - Automated Feeder Management Implementation Roadmap - Leaders

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision 2011-12	2013-14	2015-16	2017-18	2019-20	CA POU 2020 Smart Grid Vision
Planning	Adjust Implementation/ Deployment Plans based on results of pilots. Identify scope and location of feeder scale deployments.		Adjust plans based on results of feeder level deployments and prioritize system wide deployment for desired effect			
	Construct and refine engineering models for pilots	Conduct analysis with engineering model to design feeder deployments	Refine engineering model as needed for real-time analysis			
Communications Infrastructure	As needed, expand telecommunications infrastructure (fiber optic, wireless, copper …) to meet latency, bandwidth, frequency, and reliability requirements to support automated feeder monitoring and management operations with consideration for terrain, coverage, security, and cost					
Instrumentation, Control & Automation	As needed, expand SCADA and substation automation to substations and circuits					
	Conduct controlled pilots of automation hardware (such as RTUs, PLCs voltage and current sensors, advanced relays, recloser controls and IEDs, and faulted circuit indicators (FCIs)) and automated switches for basic remote/automated feeder management functionality to reconfigure/switch feeders through SCADA by remotely controlling automated switches, reclosers on select feeder(s)/substation(s)	Advance pilots to feeder and then substation area level deployments. Prioritize for desired impact. Measure and test results to determine costs/benefits.				Improve system stability and reduce losses by enabling distribution reconfiguration for load balancing and/or outage isolation
	Conduct controlled pilots for basic fault detection and isolation through SCADA by remotely monitoring FCIs, sensors, and remotely controlling automated switches, reclosers, and relays on select feeder(s)/ substation(s)	Advance pilots to feeder and then substation area level deployments. Prioritize for desired impact. Measure and test results to determine costs/benefits.				Improve customer service reliability by reducing outage extent and duration
Information Technology	Construct and refine geospatial network model with asset connectivity and line impedence data. Integrate GIS (asset information), CIS (customer information) and EA (asset specifications and connectivity) for a complete view of network model.	Update geospatial network model per new deployments and system configurations, and advance integration effectiveness				
	Implement Outage Management System (OMS) and Interactive Voice Response (IVR) system if needed. Integrate OMS (outage information) with GIS/CIS and SCADA to provide a complete view of outage and system status information to dispatch operators	Advance integration effectiveness				Improve dispatch operations efficiency and productivity

Table 35: Distribution Automation - Automated Feeder Management Implementation Roadmap - Leaders

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision					CA POU 2020 Smart Grid Vision
	2011-12	2013-14	2015-16	2017-18	2019-20	
Information Technology (continued)	Evaluate master or distributed system software for automated feeder management with fault detection/location capability. Evaluate system integration needs especially with SCADA, GIS, OMS, CIS, DMS, AMI/MDMS, EA and EMS and define requirements	Procure, deploy and test a master or distributed system software (SCADA/DMS/3rd party Fault Detection, Isolation, and Restoration (FDIR)) and integrate with SCADA, DMS, OMS/GIS, AMI/MDMS, Distributed Energy Resource (DER) control systems, Energy Management Systems (if available), and engineering analysis tools/applications	Conduct controlled pilots for automatic system topology reconfiguration for achieving self-healing grids through master or distributed system software (SCADA/DMS/3rd party) on select feeder(s)/ substation(s) and advance integration effectiveness	Conduct real-time engineering flow analysis to coordinate reconfiguration among multiple substations and feeders for self-healing grid operations to optimize system efficiencies and reliability for emergencies, load balancing, outage isolation and power quality improvements through master station in an automated fashion		Improve system stability and reduce/avoid line worker hours and mileage to find distribution system faults thus reduce GHG emissions
Standards	Evaluate, adopt and implement standards (communications, interoperability, cyber security, …) as needed around the preferred technologies/vendors that will underlie future Smart Grid implementations		Actively participate in advancement and extension of standards			
Training	Identify and develop training requirements with emphasis on field and operating personnel. Train SCADA technicians on programming the relays, and recloser controls, RTUs and other hardware components and distribution operators on OMS/control center application	Revise training as needed by evolution of standards and choices of equipment and systems. Train distribution operators on integrated master station software and protection engineers on automated feeder management capability. Reevaluate workforce needs.	Advance extent and depth of training as technological complexity increase with scale of deployment			Improve acceptance, safety and efficiency

Table 36: Distribution Automation - Automated Feeder Management Implementation Roadmap - Followers

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision					CA POU 2020 Smart Grid Vision
	2011-12	2013-14	2015-16	2017-18	2019-20	
Planning	Develop a business case for SA and DA with consideration for automated feeder management		Develop Implementation/ Deployment Plans based on results of pilots. Identify scope and location of feeder scale deployments.		Adjust plans based on results of feeder level deployments and prioritize system wide deployment for desired effect	
			Construct and refine engineering models for pilots	Conduct analysis with engineering model to design feeder deployments		
Communications Infrastructure	Assess telecommunications infrastructure needs to support automated feeder management operations	Identify, procure & test communication system elements	Conduct controlled pilots of communication technologies with consideration for terrain, coverage, security, reliability, latency and cost	Invest in/expand telecommunications infrastructure (fiber optic, wireless, copper …) to meet latency, bandwidth, frequency, and reliability requirements to support automated feeder monitoring and management operations with consideration for terrain, coverage, security, and cost		
Instrumentation, Control & Automation	Assess existing SA and DA capabilities	Invest in/expand SCADA and substation automation to substations and circuits				
	Identify/ select Smart Grid technologies to prototype/ test with	Conduct prototyping/testing of automation hardware (such as RTUs, PLCs voltage and current sensors, advanced relays, recloser controls and IEDs, and faulted circuit indicators (FCIs)) and automated switches	Conduct controlled pilots for basic remote/automated feeder management functionality to reconfigure/switch feeders through SCADA by remotely controlling automated switches, reclosers on select feeder(s)/substation(s)	Advance pilots to feeder and then substation area level deployments. Prioritize for desired impact. Measure and test results to determine costs/benefits.		Improve system stability and reduce losses by enabling distribution reconfiguration for load balancing and/or outage isolation
			Conduct controlled pilots for basic fault detection and isolation through SCADA by remotely monitoring FCIs, sensors, and remotely controlling automated switches, reclosers, and relays on select feeder(s)/ substation(s)	Advance pilots to feeder and then substation area level deployments. Prioritize for desired impact. Measure and test results to determine costs/benefits.		Improve customer service reliability by reducing outage extent and duration
Information Technology	Identify/select network modeling technologies/ applications (GIS, engineering analysis (EA))	Develop geospatial network model with asset connectivity and line impedance data.	Integrate GIS (asset information), CIS (customer information) and EA (asset specifications and connectivity) for a complete view of network model.	Update geospatial network model per new deployments and system configurations, and advance integration effectiveness		
	Evaluate and implement Outage Management System (OMS) and Interactive Voice Response (IVR-if needed) system and integrate these two systems		Integrate OMS (outage information) with GIS/CIS and SCADA to provide a complete view of outage and system status information to dispatch operators	Advance integration effectiveness		Improve dispatch operations efficiency and productivity

Table 36: Distribution Automation - Automated Feeder Management Implementation Roadmap - Followers

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision					CA POU 2020 Smart Grid Vision
	2011-12	2013-14	2015-16	2017-18	2019-20	
Information Technology (continued)			Evaluate master or distributed system software for automated feeder management with fault detection/location capability	Procure, deploy and test a master or distributed system software (SCADA/DMS/3rd party Fault Detection, Isolation, and Restoration (FDIR)) and integrate with SCADA, OMS/GIS for automated feeder reconfiguration and management functionality		Improve system stability and reduce/avoid line worker hours and mileage to find distribution system faults thus reduce GHG emissions
Standards	Research and evaluate standards for communications, control and security		Adopt and implement standards (communications, interoperability, cyber security …) as needed around the preferred technologies/vendors that will underlie future Smart Grid implementations. Refine equipment selections in preparation for feeder scale deployment			
Training	Assess staffing and training needs	Identify and develop training requirements with emphasis on field, engineering and operating personnel. Train distribution engineers on engineering analysis tools and network modeling	Train SCADA technicians on programming the relays, and recloser controls, RTUs and other hardware components and distribution operators on OMS	Revise training as needed by evolution of standards and choices of equipment and systems. Train distribution operators on integrated master station software and protection engineers on automated feeder management capability. Reevaluate workforce needs.		Improve acceptance, safety and efficiency

Table 37: Distribution Automation - Integrated Voltage Management Implementation Roadmap - Leaders

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision: 2011-12	2013-14	2015-16	2017-18	2019-20	CA POU 2020 Smart Grid Vision
Planning	Adjust Implementation/Deployment Plans based on results of pilots. Identify scope and location of feeder scale deployments.		Adjust plans based on results of feeder level deployments and prioritize system wide deployment for desired effect.			
	Construct and refine engineering models for pilots.	Conduct analysis with engineering model to design feeder deployments.	Refine engineering model as needed for real-time analysis.			
Communications Infrastructure	As needed, expand telecommunications infrastructure (fiber optic, wireless, copper …) to meet latency, bandwidth, frequency, and reliability requirements to support voltage monitoring and management operations with consideration for terrain, coverage, security, and cost.					
Instrumentation, Control & Automation	As needed, expand SCADA and substation automation to substations and circuits.					
	Conduct controlled pilots of automation hardware (such as voltage sensors/regulators, capacitor banks, LTCs) and controllers (regulator controllers, cap bank controllers, LTC controllers, RTUs, IEDs, PLCs) to manage reactive power through SCADA by remotely controlling cap banks on select feeder(s)/ substation(s).	Advance pilots to feeder and then substation area level deployments. Prioritize for desired impact. Measure and test results to determine costs/benefits.				Improve system efficiency and power quality.
	Conduct controlled pilots for CVR to monitor and control system voltage and demonstrate customer energy efficiency benefits through SCADA by remotely controlling LTCs, substation and down-line (feeder) voltage regulators with microprocessor-based controllers and customer advanced meters on select feeder(s)/ substation(s).	Advance pilots to feeder and then substation area level deployments. Prioritize for desired impact. Measure and test results to determine costs/benefits.				Reduce system demand and losses, enhance grid capacity, and thus reduce energy/demand charges.
	Conduct controlled pilots with controllable power inverter technology for distributed energy resources (renewables, storage, PV) integration and voltage regulation on select feeder(s)/substation(s).	Advance pilots to feeder and then substation area level deployments. Prioritize for desired impact. Measure and test results to determine costs/benefits in conjunction with distributed generation, storage, and electric vehicle charging.				Integrate and control DER for grid reliability, stability and efficiency.

Table 37: Distribution Automation - Integrated Voltage Management Implementation Roadmap - Leaders

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision					CA POU 2020 Smart Grid Vision
	2011-12	2013-14	2015-16	2017-18	2019-20	
Information Technology	Evaluate master or distributed system software for integrated Volt/VAr and CVR management and autonomous functionality. Evaluate system integration needs especially with SCADA, GIS, OMS, DMS, AMI/MDMS, EA and EMS and define requirements.	Procure, deploy and test a master or distributed system software (SCADA/DMS/3rd party) for integrated VVO/CVR functionality. Integrate master or distributed system software with AMI/MDMS, Distributed Energy Resource (DER) control systems, Energy Management Systems (if available), OMS/GIS and engineering analysis tools/ applications (if needed).	Conduct controlled pilots for integrated and automated voltage management through master or distributed system software (SCADA/DMS/3rd party) to optimize voltage on select feeder(s)/ substation(s) and advance integration effectiveness.	Conduct real-time engineering flow analysis to optimize and control system voltage/CVR through master station in an automated fashion including the control of DER technologies.		Reduce GHG emissions.
Standards	Evaluate, adopt and implement standards (communications, interoperability, cyber security, …) as needed around the preferred technologies/vendors that will underlie future Smart Grid implementations.		Actively participate in advancement and extension of standards for voltage management.			
Training	Identify and develop training requirements with emphasis on engineering and operating personnel. Train SCADA technicians on controllers, RTUs and other hardware components. Train distribution engineers on engineering analysis tools and network modeling.	Revise training as needed by evolution of standards and choices of equipment and systems. Train distribution operators on integrated master station software and advanced engineering analysis tools. Reevaluate workforce needs.	Advance extent and depth of training as technological complexity increase with scale of deployment.			

Table 38: Distribution Automation - Integrated Voltage Management Implementation Roadmap - Followers

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision					CA POU 2020 Smart Grid Vision
	2011-12	2013-14	2015-16	2017-18	2019-20	
Planning	Develop a business case for SA and DA with consideration for voltage management		Develop Implementation/ Deployment Plans based on results of pilots. Identify scope and location of feeder scale deployments.		Adjust plans based on results of feeder level deployments and prioritize system wide deployment for desired effect	
			Construct and refine engineering models for pilots	Conduct analysis with engineering model to design feeder deployments		
Communications Infrastructure	Assess telecommunications infrastructure needs to support voltage management operations	Identify, procure & test communication system elements	Conduct controlled pilots of communication technologies with consideration for terrain, coverage, security, reliability, latency and cost	Invest in/expand telecommunications infrastructure (fiber optic, wireless, copper …) to meet latency, bandwidth, frequency, and reliability requirements to support voltage monitoring and management operations with consideration for terrain, coverage, security, and cost		
Instrumentation, Control & Automation	Assess existing SA and DA capabilities	Invest in/expand SCADA and substation automation to substations and circuits				
	Identify/select Smart Grid technologies to prototype / test with	Conduct prototyping/testing of automation hardware (such as voltage sensors/regulators, capacitor banks, LTCs) and controllers (regulator controllers, cap bank controllers, LTC controllers, RTUs, IEDs, PLCs)	Conduct controlled pilots of automation hardware (such as voltage sensors/regulators, capacitor banks, LTCs) and controllers (regulator controllers, cap bank controllers, LTC controllers, RTUs, IEDs, PLCs) to manage reactive power through SCADA by remotely controlling cap banks on select feeder(s)/ substation(s)	Advance pilots to feeder and then substation area level deployments. Prioritize for desired impact. Measure and test results to determine costs/benefits.		Improve system efficiency and power quality
			Conduct controlled pilots for CVR to monitor and control system voltage and demonstrate customer energy efficiency benefits through SCADA by remotely controlling LTCs, substation and down-line (feeder) voltage regulators with microprocessor-based controllers and customer advanced meters (AMR-if available) on select feeder(s)/ substation(s)	Advance pilots to feeder and then substation area level deployments. Prioritize for desired impact. Measure and test results to determine costs/benefits.		Reduce system demand and losses, enhance grid capacity, thus reduce energy/demand charges
Information Technology	Identify/select network modeling technologies/ applications (GIS, engineering analysis (EA))	Develop geospatial network model with asset and connectivity data for a complete view of network model.				

Table 38: Distribution Automation - Integrated Voltage Management Implementation Roadmap - Followers

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision					CA POU 2020 Smart Grid Vision
	2011-12	2013-14	2015-16	2017-18	2019-20	
			Evaluate master or distributed system software for integrated Volt/VAr and CVR management and autonomous functionality. Evaluate system integration needs especially with SCADA, GIS, EA and define requirements	Procure, deploy and test a master or distributed system software (SCADA/DMS/3rd party) for integrated VVO/CVR functionality. Integrate master or distributed system software with OMS/GIS and engineering analysis tools/ applications		Reduce GHG emissions
Standards	Research and evaluate standards for communications, control and security		Adopt and implement standards (communications, interoperability, cyber security…) as needed around the preferred technologies/vendors that will underlie future Smart Grid implementations. Refine equipment selections in preparation for feeder scale deployment			
Training	Assess staffing and training needs	Identify and develop training requirements with emphasis on field and operating personnel.	Train SCADA technicians on controllers, RTUs and other hardware components	Revise training as needed by evolution of standards and choices of equipment and systems. Train distribution operators on integrated master station software and advanced engineering analysis tools. Reevaluate workforce needs.		

Table 39: Electric Vehicle Charging Implementation Roadmap - Leaders

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision					CA POU 2020 Smart Grid Vision
	2011-12	2013-14	2015-16	2017-18	2019-20	
Planning	Adjust Implementation/ Deployment Plans for distributed energy resources (DER) including Electric Vehicle (EV) integration to the grid based on results of pilots. Identify scope and location of feeder scale deployments.		Adjust plans based on results of feeder level deployments and prioritize system wide deployment for desired effect			
	Develop/extend pilot dynamic rate and incentive programs (such as Critical Peak Pricing (CPP), time variant rates,...and so forth.) for EV customers to encourage charging during off-peak hours and feed-in tariffs for drawing power from EV's battery for customer/utility use. Communicate and educate customers on these programs. Enroll customers to these programs for pilots.		Extend dynamic rate programs and incentive programs for all customers including feed-in tariffs for drawing power from EV's battery for customer/utility use. Develop pilot rate and incentive programs for EV customers to encourage discharging during emergency, peak-hours when required by the utility and/or the regional authorities. Communicate and educate customers on these programs. Enroll customers to these programs for pilots			
	Construct and refine engineering models for EV integration pilots	Conduct engineering analysis to determine the impact of EV charging station deployments on the grid and to better prepare capital and operation expenditure plans focusing on the right areas for system improvement, maintenance and expansion.		Refine engineering models/analysis as needed for near real-time analysis, integrated resource planning including dynamic and optimized planning and management of EVs in response to demand response (DR) and system reliability events.		Improve system planning for EV integration
Communications Infrastructure	Invest in/expand DA/AMI telecommunications infrastructure (fiber optic, wireless, copper …) to meet latency, bandwidth, frequency, and reliability requirements to support EV integration and management operations with consideration for terrain, coverage, security, and cost. Invest in /expand Home-Area-Network (HAN) deployments in order to support advanced EV control and management functions for demand response (DR), direct load control and system reliability.					
Instrumentation, Control & Automation	As needed, expand SCADA and substation automation to substations and circuits					
	Enable construction/deployment of utility/3rd party owned EV charging stations and ensure that the necessary electrical infrastructure (such as changes may be required for Level II, 220V charging) is in place.					
	Conduct controlled pilots with net-metering technologies and dynamic rate programs including feed-in tariffs for drawing power from EV's battery for customer/utility use. Monitor and measure EV customers' load profiles and changes on select feeder(s)/substation(s). Conduct controlled pilots with in-home displays (IHDs) to communicate EV charging status, market/rate information, and DR/direct load control events to the customers.		Advance pilots with feed-in tariffs for drawing power from EV's battery for localized customer and/or utility use. Monitor, measure and control impact on the grid. Advance pilots to feeder and then substation area deployments. Prioritize for desired impact. Measure and test results to determine costs/benefits.			Reduce energy and demand charges
	Conduct controlled pilots with advanced protection and operation technologies (such as Low Voltage ride-through (LVRT) and anti-islanding) that manage bi-directional power flow in distribution circuits for drawing power from EVs on select feeder(s)/substation(s)		Advance pilots to other substations and feeders. Prioritize for desired impact. Measure and test results to determine costs/benefits in conjunction with distributed generation and storage.			Improve integration and control of EV charging/discharging status for grid reliability, stability and efficiency.

Table 39: Electric Vehicle Charging Implementation Roadmap - Leaders

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision					CA POU 2020 Smart Grid Vision
	2011-12	2013-14	2015-16	2017-18	2019-20	
	Conduct controlled pilots with controllable power inverter technology for EV charging stations, voltage sensors/regulators and controllers by monitoring and remotely controlling power inverters, voltage regulators and controllers through SCADA on select feeder(s)/substation(s)	Advance pilots to enable automated control of EV charging status in response to demand response (DR) and system reliability events. Advance pilots to feeder and then substation area deployments. Prioritize for desired impact. Measure and test results to determine costs/benefits in conjunction with DR and system reliability activities.				Integrate and control of EVs for grid reliability, stability and efficiency
Information Technology	Construct and refine geospatial network model with asset connectivity and asset data. Integrate GIS (asset information), CIS (customer information) and EA (asset specifications and connectivity) for a complete view of network model.	Update geospatial network model per new EV charging station and related technologies deployments, and advance integration effectiveness				
	Evaluate master or distributed system software for Distributed Energy Resource (DER) control systems and/or EV control systems. Evaluate system integration needs especially with SCADA, DMS, AMI/MDMS, GIS, and engineering analysis (EA) tools/applications and define requirements	Procure, deploy and test a master or distributed system software for control and management of EV charging status. Integrate master or distributed system software with SCADA, DMS, AMI/MDMS, GIS, and EA tools/ applications	Conduct controlled pilots for advanced control and management of EV charging/discharging status through master or distributed system software in response to DR/ direct load control events on select feeder(s)/ substation(s) and advance integration effectiveness	Conduct real-time engineering flow analysis to optimize and control of EV charging/discharging status through master station in an automated fashion in response to demand response (DR), direct load control and system reliability events.		Improve control and management of EV charging status for DR purposes. Reduce energy consumption and demand.

Table 39: Electric Vehicle Charging Implementation Roadmap - Leaders

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision: 2011-12	2013-14	2015-16	2017-18	2019-20	CA POU 2020 Smart Grid Vision
	Evaluate master or distributed system software for integrated Volt/VAr and CVR management and autonomous functionality. Evaluate system integration needs especially with SCADA, GIS, OMS, DMS, AMI/MDMS, EA and EMS and define requirements	Procure, deploy and test a master or distributed system software (SCADA/DMS/3rd party) for integrated VVO/CVR functionality. Integrate master or distributed system software with AMI/MDMS, Distributed Energy Resource (DER) control systems, Energy Management Systems (if available), OMS/GIS and engineering analysis tools/ applications (if needed)	Conduct controlled pilots for integrated and automated voltage management through master or distributed system software (SCADA/DMS/3rd party) to optimize voltage on select feeder(s)/ substation(s) and advance integration effectiveness	Conduct real-time engineering flow analysis to optimize and control system voltage/CVR through master station in an automated fashion including the control of EV charging status in response to system reliability events.		Reduce GHG emissions and environmental footprint
Standards	Evaluate, adopt and implement standards (communications, interoperability, cyber security…) for EV integration related technologies and management and control of these resources for system reliability, DR and direct load control events as needed around the preferred technologies/vendors that will underlie future Smart Grid implementations. Refine equipment selections in preparation for feeder scale deployment		Actively participate in advancement and extension of standards			
Training	Identify and develop training requirements with emphasis on field, engineering and operating personnel. Train SCADA technicians on programming the relays, and recloser controls, RTUs and other hardware components. Train field personnel on net-metering and EV charging/integration technologies. Train distribution engineers on engineering analysis tools and network modeling	Revise training as needed by evolution of standards and choices of equipment and systems. Train distribution engineers on downloading/ exporting historical operational and performance data for advanced engineering analysis and trending applications. Train distribution operators on integrated master station software. Reevaluate workforce needs.	Advance extent and depth of training as technological complexity increase with scale of deployment. Train distribution engineers on advanced engineering analysis applications/solutions for advanced system reliability and resource planning. Reevaluate workforce needs.	Advance extent and depth of training for distribution engineers for near real-time engineering analysis tools/applications enabling dynamic management and control of EVs as DERs, system configurations and assets. Reevaluate workforce needs.		Improve acceptance, safety, efficiency and reliability

Table 40: Electric Vehicle Charging Implementation Roadmap - Followers

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision					CA POU 2020 Smart Grid Vision
	2011-12	2013-14	2015-16	2017-18	2019-20	
Planning	Develop a business case for distributed energy resources (DER) including Electric Vehicle (EV) integration to the grid		Develop Implementation/ Deployment Plans based on results of pilots. Identify scope and location of feeder scale deployments.		Adjust plans based on results of feeder level deployments and prioritize system wide deployment for desired effect	
	Develop pilot rate and incentive programs for EV customers to encourage charging during off-peak hours. Communicate and educate customers on these programs. Enroll customers to these programs for pilots		Extend pilot rate and incentive programs for EV customers including drawing power from EV's battery for customer's localized use. Develop pilot rate and incentive programs for EV customers to encourage discharging during emergency, peak-hours when required by the utility and/or the regional authorities for their own use. Communicate and educate customers on these programs. Enroll customers to these programs for pilots			
			Construct and refine engineering models for EV integration pilots	Conduct engineering analysis to determine the impact of EV charging station deployments on the grid and to better prepare capital and operation expenditure plans focusing on the right areas for system improvement, maintenance and expansion		Improve system planning for EV integration
Communications Infrastructure	Assess telecommunications infrastructure needs to support EV integration and management	Identify, procure & test communication system elements (AMI, DA)	Conduct controlled pilots of communication technologies (AMI, DA) with consideration for terrain, coverage, security, reliability, latency and cost	Invest in/expand telecommunications infrastructure (fiber optic, wireless, copper …) to meet latency, bandwidth, frequency, and reliability requirements to support EV integration and management operations with consideration for terrain, coverage, security, and cost		
Instrumentation, Control & Automation	Assess existing SCADA and SA capabilities	Invest in/expand SCADA and substation automation to substations and circuits				
	Enable construction/deployment of utility/3rd party owned EV charging stations and ensure that the necessary electrical infrastructure (such as changes may be required for Level II, 220V charging) is in place.					
	Identify/select metering technologies to pilot with. Procure, deploy and test advanced metering technologies with net-metering capability for EV customers.	Conduct controlled pilots with net-metering technologies to monitor and measure EV customers' load profiles and changes on select feeder(s)/substation(s). Conduct controlled pilots with in-home displays (IHDs) to present on-site EV charging status and cost information to the customer.		Advance pilots for drawing power from EV's battery for localized customer use. Monitor, measure and control impact on the grid. Advance pilots to feeder and then substation area deployments. Prioritize for desired impact. Measure and test results to determine costs/benefits.		Reduce energy and demand charges
	Identify/select EV integration technologies to prototype/ test with	Conduct prototyping/testing of controllable power inverter technology, voltage sensors/regulators and controllers for EV integration	Conduct controlled pilots with controllable power inverter technology for EV charging stations and voltage regulation by monitoring and remotely controlling power inverters, voltage regulators and controllers through SCADA on select feeder(s)/substation(s)	Advance pilots to enable automated control of EV charging status in response to demand response (DR), system reliability events. Advance pilots to feeder and then substation area deployments. Prioritize for desired impact. Measure and test results to determine costs/benefits in conjunction with DR and system reliability activities.		Integrate and control of EV charging status for grid reliability, stability and efficiency
Information Technology	Identify/select network modeling technologies/ applications (GIS, engineering analysis (EA))	Develop geospatial network model with asset and connectivity data for a complete view of network model.		Update geospatial network model per new EV charging station deployments and related technologies, and advance integration effectiveness		

Table 40: Electric Vehicle Charging Implementation Roadmap - Followers

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision					CA POU 2020 Smart Grid Vision
	2011-12	2013-14	2015-16	2017-18	2019-20	
Information Technology (continued)			Evaluate master or distributed system software for Distributed Energy Resource (DER) control systems and/or EV control systems. Evaluate system integration needs especially with SCADA, GIS, and engineering analysis (EA) tools/applications and define requirements	Procure, deploy and test a master or distributed system software for control and management of EV charging status. Integrate master or distributed system software with SCADA, advanced metering systems, GIS, and EA tools/ applications		Improve control and management of EV charging status for DR purposes. Reduce energy consumption and demand.
			Evaluate master or distributed system software for integrated Volt/VAr and CVR management and autonomous functionality. Evaluate system integration needs especially with SCADA, GIS, and EA and define requirements	Procure, deploy and test a master or distributed system software (SCADA/DMS/3rd party) for integrated VVO/CVR functionality. Integrate master or distributed system software with OMS/GIS and engineering analysis tools/ applications		Reduce GHG emissions and environmental footprint
Standards	Research and evaluate standards for communications, control and security		Adopt and implement standards (communications, interoperability, cyber security…) as needed around the preferred technologies/vendors that will underlie future Smart Grid implementations. Refine equipment selections in preparation for feeder scale deployment			
Training	Assess staffing and training needs.	Identify and develop training requirements with emphasis on field, engineering and operating personnel. Train field personnel on net-metering and EV charging/integration technologies. Train distribution engineers on engineering analysis tools and network modeling	Train SCADA technicians on controllers, RTUs and other hardware components. Train field personnel on power inverter technologies for integration of EV. Train engineering personnel on advanced engineering analysis for EV integration	Revise training as needed by evolution of standards and choices of equipment and systems. Train distribution operators on integrated master station software. Reevaluate workforce needs.		Improve acceptance, safety, efficiency and reliability

Table 41: Asset Management Implementation Roadmap - Leaders

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision: 2011-12	2013-14	2015-16	2017-18	2019-20	CA POU 2020 Smart Grid Vision
Planning	Adjust Implementation/ Deployment Plans with consideration for asset management and performance optimization based on results of pilots. Identify scope and location of feeder scale deployments.		Adjust plans based on results of feeder level deployments and capital and operational plans. Prioritize system wide deployment for desired effect.			
	Construct and refine engineering models and analysis tools for pilots. Construct and develop load forecasts (system, substation, feeder level)	Conduct loading analysis, loss analysis, voltage/reliability analysis and fault analysis with engineering analysis tool(s)/application(s) using both actual operational and condition/status data from system assets to better prepare capital and operation expenditure plans focusing on the right areas for system improvement, maintenance and expansion.		Refine engineering models/analysis as needed for near real-time analysis, integrated resource planning including dynamic and optimized planning and management of DERs		Improve capital and operation expenditure plans
Communications Infrastructure	As needed, expand telecommunications infrastructure (fiber optic, wireless, copper …) to meet latency, bandwidth, frequency, and reliability requirements to support asset monitoring and management operations with consideration for terrain, coverage, security, and cost					
Instrumentation, Control & Automation	As needed, expand SCADA and substation automation to substations and circuits					
	Conduct controlled pilots of sensor technologies (such as voltage, current, temperature, PD, moisture, vibration, and so forth) such as IEDs, relay and recloser controls that have the ability to log oscillograph data for protection analysis and data acquisition RTUs for basic asset monitoring and visualization functionality to automate asset status and performance data collection through SCADA and analysis on select substation(s)	Advance pilots to other substations and feeders. Prioritize for desired impact. Measure and test results to determine costs/benefits.				Improve asset monitoring and reliability
	Conduct controlled pilots for condition-based, predictive maintenance practices on select substation(s) assets utilizing actual asset status and performance data collected through SCADA by remotely monitoring IEDs, sensors, and RTUs	Advance pilots to other substations and feeders and asset classes. Prioritize for desired impact. Measure and test results to determine costs/benefits.				Maximize asset utilization and life, and reduce maintenance and inspection costs.
Information Technology	Construct and refine geospatial network model with asset connectivity and asset data. Integrate GIS (asset information), CIS (customer information) and EA (asset specifications and connectivity) for a complete view of network model.	Update geospatial network model per new deployments and system configurations, and advance integration effectiveness				

Table 41: Asset Management Implementation Roadmap - Leaders

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision					CA POU 2020 Smart Grid Vision
	2011-12	2013-14	2015-16	2017-18	2019-20	
Information Technology (continued)	Implement Outage Management System (OMS) and Interactive Voice Response (IVR) system if needed. Integrate OMS (outage information) with GIS/CIS and SCADA to provide a complete view of outage and system status information	Advance integration effectiveness				
	Evaluate master or distributed system software for asset management with condition-based maintenance capability. Evaluate system integration needs especially with SCADA, GIS, OMS, CIS, DMS, AMI/MDMS, EA and EMS and define requirements	Procure, deploy and test a master or distributed system software (SCADA/DMS/3rd party Condition-based Maintenance solution) and integrate with SCADA, DMS, OMS/GIS, AMI/MDMS, Distributed Energy Resource (DER) control systems, Energy Management Systems (if available), and engineering analysis tools/applications for asset management and maintenance functionality	Conduct controlled pilots for expanded resource planning using actual and more granular operational and condition/status data from system assets for advanced engineering analysis (Volt/VAr analysis and optimization, CVR, load forecasting, DR, PV and DER integration and management) on select feeder(s)/ substation(s) and advance integration effectiveness	Conduct near real-time engineering analysis, integrated resource planning including dynamic and optimized planning and management of DERs. Enable automation/ control by design by integrating circuit reconfiguration and asset control and management functionalities through master DMS station to prevent and mitigate safety, reliability and stability risks before they happen in near real-time.		Maximize asset utilization and life, and reduce maintenance and inspection costs. Improve integration and control of DER for grid reliability, stability and efficiency. Thus reduce GHG emissions
Standards	Evaluate, adopt and implement standards (communications, interoperability, cyber security…) for asset monitoring and management as needed around the preferred technologies/vendors that will underlie future Smart Grid implementations. Refine equipment selections in preparation for feeder scale deployment		Actively participate in advancement and extension of standards			
Training	Identify and develop training requirements with emphasis on field, engineering and operating personnel. Train SCADA technicians on programming the relays, and recloser controls, RTUs and other hardware components	Revise training as needed by evolution of standards and choices of equipment and systems. Train distribution engineers on downloading/exporting historical operational and performance data for advanced engineering analysis and trending applications	Advance extent and depth of training as technological complexity increase with scale of deployment. Train distribution engineers on advanced engineering analysis applications/solutions for system improvement, maintenance and expansion planning. Reevaluate workforce needs.	Advance extent and depth of training for distribution engineers for near real-time engineering analysis tools/applications enabling dynamic management and control of system configurations and assets. Reevaluate workforce needs.		Improve acceptance, safety, efficiency and reliability

Table 42: Asset Management Implementation Roadmap - Followers

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision					CA POU 2020 Smart Grid Vision
	2011-12	2013-14	2015-16	2017-18	2019-20	
Planning	Develop a business case for SA and DA with consideration for asset management and performance optimization		Develop Implementation/ Deployment Plans based on results of pilots. Identify scope and location of feeder scale deployments.		Adjust plans based on results of feeder level deployments and capital and operational plans. Prioritize system wide deployment for desired effect.	
			Construct and refine engineering models and analysis tools for pilots. Construct and develop load forecasts (system, substation, feeder level)	Conduct loading analysis, loss analysis, voltage/reliability analysis and fault analysis with engineering analysis tool(s)/application(s) using both actual operational and condition/status data from system assets to better prepare capital and operation expenditure plans focusing on the right areas for system improvement, maintenance and expansion		Improve capital and operation expenditure plans
Communications Infrastructure	Assess telecommunications infrastructure needs to support asset monitoring and management operations	Identify, procure & test communication system elements	Conduct controlled pilots of communication technologies with consideration for terrain, coverage, security, reliability, latency and cost	Invest in/expand telecommunications infrastructure (fiber optic, wireless, copper …) to meet latency, bandwidth, frequency, and reliability requirements to support asset monitoring and management operations with consideration for terrain, coverage, security, and cost		
Instrumentation, Control & Automation	Assess existing SA and DA capabilities	Invest in/expand SCADA and substation automation to substations and circuits				
	Identify/select Smart Grid technologies to prototype/ test with	Conduct prototyping/testing of sensor technologies (such as voltage, current, temperature, PD, moisture, vibration, and so forth) such as IEDs, relay and recloser controls that have the ability to log oscillograph data for protection analysis and data acquisition RTUs	Conduct controlled pilots for basic asset monitoring and visualization functionality to automate asset status and performance data collection through SCADA and analysis on select substation(s)	Advance pilots to other substations and feeders. Prioritize for desired impact. Measure and test results to determine costs/benefits.		Improve asset monitoring and reliability
			Conduct controlled pilots for condition-based, predictive maintenance practices on select substation(s) assets utilizing actual asset status and performance data collected through SCADA by remotely monitoring IEDs, sensors, and RTUs	Advance pilots to other substations and feeders. Prioritize for desired impact. Measure and test results to determine costs/benefits.		Extend asset life and utilization factors and reduce maintenance and inspection costs
Information Technology	Identify/select network modeling technologies/ applications (GIS, engineering analysis (EA))	Develop geospatial network model with asset connectivity and asset data.	Integrate GIS (asset information), CIS (customer information) and EA (asset specifications and connectivity) for a complete view of network model.	Update geospatial network model per new deployments and system configurations, and advance integration effectiveness		

Table 42: Asset Management Implementation Roadmap - Followers

Strategic Focus Areas	Key Milestones to Achieve 2020 Smart Grid Vision					CA POU 2020 Smart Grid Vision
	2011-12	2013-14	2015-16	2017-18	2019-20	
Information Technology (continued)	Evaluate and implement Outage Management System (OMS) and Interactive Voice Response (IVR-if needed) system and integrate these two systems		Integrate OMS (outage information) with GIS/CIS and SCADA to provide a complete view of outage and system status information	Advance integration effectiveness		
			Evaluate master or distributed system software for asset management with condition-based maintenance capability	Procure, deploy and test a master or distributed system software (SCADA/DMS/3rd party Condition-based Maintenance solution) and integrate with SCADA, OMS/GIS, and engineering analysis tools for asset management and maintenance functionality		Extend asset life and utilization factors and reduce maintenance and inspection costs
Standards	Research and evaluate standards for communications, control and security		Adopt and implement standards (communications, interoperability, cyber security…) for asset monitoring and management as needed around the preferred technologies/vendors that will underlie future Smart Grid implementations. Refine equipment selections in preparation for feeder scale deployment			
Training	Assess staffing and training needs	Identify and develop training requirements with emphasis on field, engineering and operating personnel. Train distribution engineers on engineering analysis tools and network modeling	Train SCADA technicians on programming the relays, and recloser controls, RTUs and other hardware components and distribution engineers on downloading/exporting historical operational and performance data for engineering analysis and trending applications	Revise training as needed by evolution of standards and choices of equipment and systems. Train distribution engineers on advanced engineering analysis applications/solutions for system improvement, maintenance and expansion planning. Reevaluate workforce needs.		Improve acceptance, safety, efficiency and reliability

CHAPTER 7: Conclusions

This report identifies a number of important aspects that affect the advent of Smart Grid in California's POUs and their role in addressing California's energy policies. It investigates these issues to answer several key questions discussed below.

How Does the Deployment of Smart Grid Technology Help a POU Achieve State Energy Policy Objectives?

California has a broad range of energy policy objectives that impact the customer-owners of POU's. The overarching objective of California's energy policy is to reduce the use of fossil-based fuels that when consumed in producing electricity generates greenhouse gasses (GHG) that are emitted to the atmosphere. These policies and related regulations and legislation direct utilities to:

- Reduce energy use by increasing energy efficiency in customer premises and in the grid;
- Reduce the use of fossil-fueled energy sources by increasing the use of clean renewable energy resources;
- Motivate, and in some instances require, consumers to reduce energy use during peak consumption periods when energy is most scarce, is most expensive to produce and deliver and is generated by the least efficient, highest-GHG emitting sources; and,
- Provide efficient, reliable, secure and resilient transmission and distribution grids.

In response to the federal direction that states consider advancing Smart Grid technologies, particularly those technologies that could advance energy efficiency, demand response, renewable energy and grid reliability and security, in 2009 California enacted Senate Bill 17 into the Public Utilities Code. The bill establishes as state policy the modernization of the state's electrical grid to maintain reliable and secure electrical service with infrastructure that can meet future growth in demand while achieving several other objectives such as integration of distributed generation resources, demand-side resources and 'smart' technologies. The Bill further required California's investor owned and large publicly-owned utilities to develop plans that consider the deployment of Smart Grid technologies.

Through this research, SAIC identified seven use cases to illustrate ways in which Smart Grid is widely expected to benefit utilities and energy users in California and elsewhere in 2020. Use cases are different from business cases in that a business case provides the justification for the project. Whereas, a use case, within the context of this report, provides a high-level description of a specific Smart Grid application from a business process perspective. Use cases identify the applications that will be enabled (such as, what devices or technologies would be used and what the interactions would be between various Smart Grid applications), and the primary business, operational and technical requirements.

The key energy policy objectives that can be achieved through the implementation of these seven key applications of Smart Grid technologies, referred as ‘use cases’, are presented below.

Figure 39: Seven Use Cases Define POU Application of Smart Grid Technologies

Seven Use Cases Define Utility Application of Smart Grid Technologies	Key Energy Policy Objectives						
	Reduce GHG	Demand Response	Energy Efficiency	Renewable Energy	Grid Resiliency	Distributed Energy	Electric Vehicles
SUBSTATION AUTOMATION Integrated Protection and Control Improves Service Reliability				✓	✓	✓	
ADVANCED METERING Smart Meters Enhance Utility-Customer Interaction	✓	✓		✓			
DISTRIBUTED ENERGY RESOURCES Integrated Distributed Generation & Storage Provides Reliable Clean Renewable Energy	✓		✓		✓	✓	
DEMAND RESPONSE Active load management reduces peak demand	✓		✓		✓	✓	✓
DISTRIBUTION AUTOMATION Voltage Management Improves Power Quality, Delivery Efficiency, and Customer Service	✓		✓		✓		
ELECTRIC VEHICLE CHARGING Grid Monitoring and Control Enables Wide-scale Electric Vehicle Charging	✓						✓
ASSET MANAGEMENT Asset Monitoring Enables Proactive System Planning and Maintenance	✓		✓	✓	✓	✓	✓

A brief description of each use case is presented below.

1. **Substation Automation -** Substation automation can help utilities meet energy policy objectives by allowing bidirectional flow of power through protection and control devices design for power flowing only to the customer; by providing a communications interface for advanced metering and distribution area networks; and by providing enhanced security and asset management.
2. **Advanced Metering -** Advanced metering infrastructure networks provide the platform for enhanced customer service options such as: near real time energy cost and consumption information; remote service switching; pre-pay service; and, real-time outage notification data.
3. **Distributed Energy Resources (DER) -** Diverse energy sources located throughout the distribution system including: wind and solar systems; energy storage; fuel cell; and combined heat and power systems can enhance system reliability, improve system efficiency and reduce the reliance on fossil-fueled energy sources..
4. **Demand Response -** Customers actively manage their energy consumption in response to information about their energy usage, rate and market (events) information. Customer devices can either autonomously respond to rat e/event information initiated

by the utility or can be directly controlled by the utility. Advanced energy and demand management systems can optimize the dispatch of supply, demand, storage and demand response to optimize cost, efficiency and reliability.

5. **Distribution Automation -** Widespread measurement, monitoring, control and communications technologies are applied to the distribution system to reduce the extent and duration of outages; minimize electrical losses; maximize system efficiency; improve quality of service and maximize the capacity of distribution system infrastructure..
6. **Electric Vehicle Charging -** Advanced charging systems allow widespread adoption of electric vehicle charging by controlling the time of day and rate at which electric vehicles charge to minimize the cost of charging, minimize the loading on the distribution system and in some cases deliver energy back to the distribution system if needed for grid reliability and security.
7. **Asset Management -** Near real time monitoring of electric system equipment on a wide scale basis, including transformers, conductors, and protective devices can be used to optimize the maintenance and replacement of equipment thereby minimizing operating and maintenance costs while maximizing system reliability.

How Are POUs Deploying Smart Grid Technologies Today?

The use cases serve as a reference against which present and future technology capabilities are compared to define the gap between now and the possible capabilities of 2020.

California POUs are implementing the seven key smart grid applications, 'use cases', at varying paces and scales of deployment. All are in the process deploying or enabling deployment and integration of distributed energy resources and most are also in the process of deploying or expanding the deployment of substation automation. The deployment of advanced metering infrastructure varies -- while half of the POUs are already in the process of deploying, the other half is mostly planning to deploy or piloting such technology. Distribution automation and electric vehicle charging applications are the other two areas where most participating POUs either have plans to deploy or in the process of exploring their options through pilot projects. Demand response has been addressed by most utilities through time-of-use rates, although only a few large customers actually participate. Demand response through direct load control has been deployed for some time by at least one utility but is seldom used and is considered ineffective in its current state. Comprehensive, technology-driven asset management is the least adopted application by all participating utilities. Table 43 provides an overview of the current state of deployment by participating utilities.

Table 43: Smart Grid Use Case Applications by California POUs

Use Case	ALW	AMP	APU	BWP	CPAU	GWP	IID	LADWP	PWP	REU	RPU	SMUD	SVP
Substation Automation	◒	○	◒	◒	○	◒	◒	◒	○	●	◒	◒	◒
Advanced Metering	○	○	◒	●	○	●	⊙	◒	○		○	◒	⊙
Distributed Energy Resources	◒	◒	◒	◒	◒	◒	◒	◒	◒	◒	◒	◒	◒
Demand Response			○	○	⊙	⊙	⊙	⊙				●	
Distribution Automation	○	○	⊙	○	○	⊙	○	⊙	⊙	⊙	○	◒	⊙
Electric Vehicle Charging	○	○	⊙	⊙	⊙	⊙	⊙	◒	○	○	○	◒	⊙
Asset Management			◒	○		○	○	○	○		○	◒	
○Planning ⊙Piloting ◒Deploying ●Deployed													

Smart Grid Deployment is Being Advanced by the American Recovery and Reinvestment Act Funding

This research found that the POUs who received stimulus grants are making substantive progress toward the deployment of Smart Grid. As a result of the ARRA funded programs, these utilities accelerated and expanded the scope of their smart grid strategies while reducing the cost of deployment. As these programs mature, value information will be developed as to benefits that smart grid technologies can provide to consumers.

The High Cost and Uncertainty of Benefits is a Barrier to the Deployment of Smart Grid Technologies.

The legacy of the electric utility industry is founded on the *certainty* of providing safe, reliable and economic electricity. That passion for certainty is pervasive throughout utility decision making and frequently manifests itself in pursuing business decisions and technologies which are risk adverse. In contrast, many Smart Grid applications are still relatively immature and lack a track record of proven field applications. Scarcity of historical data results in important uncertainties that subsequently affect POU's ability to accurately estimate future costs and benefits of various Smart Grid options. Since cost/benefit analysis is fundamental to a POU's approach to economically justifying Smart Grid, some POUs may elect to take a "wait and see" approach. This observation is supported by noting that eight out of the 13 surveyed POUs are classified as being Followers and only two are considered to be Leaders. Reducing the uncertainty in estimating Smart Grid costs and benefits will promote the implementation of Smart Grid in the POU space.

Regulatory Uncertainty is a Barrier to the Deployment of Smart Grid Technologies

The roles and policies of regulatory agencies regarding Smart Grid continue to evolve. POUs are concerned about how future policies might "second guess" the choices that POUs are making today.

While some of California's POU's are deploying Smart Grid technologies, others are not. The cost of technology obsolescence and interoperability are two other key areas of concern that underlie many utilities' reluctance to deploy Smart Grid technologies right away. Utilities fear technology selections and deployments may become obsolete as further mandates and policies are put into place and technologies continue to change without set standards. Thus, many POU's are waiting to better understand the potential impacts and benefits of Smart Grid technologies and evolution of standards before making a significant investment in deployment.

Smart Grid Deployment at POUs and IOUs will be Different

A number of differences exist between POUs and Investor Owned Utilities (IOU) that will influence the deployment of Smart Grid, including:

- **Governance:** POUs are governed by boards that are comprised of their consumers. POU boards are typically highly responsive to the consumers' needs and may be less educated about the technologies, services, benefits or costs that are attributed to Smart Grid.
- **Capital Resources:** POUs' access to financial resources is limited and their capital budgets are subject to the scrutiny of ratepayers. POUs generally do not maintain sufficient retained earnings to fund an extensive Smart Grid deployment.
- **Human Resources:** POU staff is generally much smaller than IOU staff. Smart Grid requires sufficient support for deployment, cyber security and back office systems. Existing POU staff is often not adequately trained in Smart Grid.
- **Financial Incentives:** Financial incentives, like ARRA grants, are temporary solutions that do not provide a long term solution to the financial challenges that many POUs face. POUs are not incentivized to maximize profits and financial benefits are returned to consumers.
- **Economies of Scale:** POUs generally have fewer customers to bear smart grid fixed costs, thereby impeding the achievement of economies of scale. Many POUs cannot develop a positive business case for smart grid technology and are unwilling to require customers to pay higher rates for the sake of technology.

What is the Vision of the 2020 Smart Grid from the Perspective of POUs?

Developing a vision of the 2020 Smart Grid from the publicly-owned utility (POU) perspective is very difficult. The participating utilities are similar in that they are locally-governed, customer-owned utilities who operate to provide safe and reliable services, provide good customer service and provide low-cost electricity, water and in some instances natural gas services to their customers. Beyond these similarities are vast array of differences.

Some common expectations of the future Smart Grid vision include:

- Low cost of service, high customer service, good reliability and effective environmental responsibility are consistent vision elements;
- Education, training and job creation are important drivers for POUs;
- Smart Grid is not in and of itself a strategic objective, rather it is one of a number of potential solutions for meeting strategic objectives
- The uncertainty of economic benefit from the deployment of Smart Grid technologies will attenuate the pace of deployment;
- By 2020, POUs will be at varying stages of maturity – some will be optimizing the application of Smart Grid technologies to achieve their service goals while many others will be in earlier stages of integration;
- Most POUs will not be pioneers of technology due to their higher level priority of providing low cost service. POUs strive to achieve high customer service and good reliability not with leading edge technologies which often cost more to implement and are hard to justify at the beginning, but with field-proven and tested technologies that have justifiable value proposition first and foremost to the utility customer; and,
- Regulatory and legislative pressures could cause adverse electric rate impacts if utilities are mandated to deploy technologies faster than they are prepared for.

As a result, the 2020 vision for California's POU's was resolved to:

> A successful Smart Grid will enhance the electric, water, and natural gas service offerings POUs provide to their local communities, and improve the efficiency and reliability of the delivery system; lower overall system cost; support clean energy job creation and will be accomplished in a financially responsible manner at a pace and scope of deployment that reflects the financial, environmental and social priorities of the communities that govern and are served by local POUs.

What are the POU's Motivations, Actions and Challenges in Implementing Smart Grid Technologies?

The participating utilities used the Smart Grid Maturity Model to establish their expected year 2020 smart grid maturity levels. Through the aspirations setting process of the model, participants identified their motivations for achieving their future visions and identified the actions to be taken and challenges that they may face along the way. Motivations are indicators as to why utilities intend to advance their smart grid maturity, actions represent the steps they will take to achieve their future aspirations and challenges reflect the obstacles that they expect to face along the way. A result of this goal setting exercise, the summary of motivations, actions and obstacles for the California POUs are identified as follows.

The most common motivations among the participants include:

- Meeting customer expectations and fulfilling social responsibility by adhering to regulatory requirements and increasing participation in green initiatives for reducing environmental impact (such as reducing greenhouse gas emissions, increasing demand response and peak shaving capabilities, increasing integration of renewable distributed energy resources and generation)

- Empowering customers to change their energy consumption by providing them with information about their energy use
- Improving customer and employee safety, reliability of service, power quality, system efficiency, and reducing operations and maintenance costs
- Contributing to local economic development and communities through job creation
- Protecting customer privacy and maintaining a high degree of cyber security.

The most common actions that participants identified as being required to achieve their 2020 vision include:

- Educating internal and external stakeholders to create a common understanding of what Smart Grid is and what its benefits are to obtain buy-in for pursuing Smart Grid related initiatives
- Developing, communicating and adopting a utility-wide vision, goals and strategy for Smart Grid
- Acquiring necessary resources to identify, implement and maintain Smart Grid and related initiatives
- Conducting pilot and proof-of-concept projects to identify what Smart Grid technologies and standards to implement
- Creating a comprehensive information technology and communications vision and strategy plan that supports anticipated Smart Grid applications
- Automating work order management, workforce management and asset management processes
- Implementing remote asset monitoring and sensing technologies to enhance pre-event awareness, asset condition and status monitoring, asset maintenance and life-cycle management processes and costs
- Deploying advanced metering infrastructures to improve customer experience by proactive outage detection and notification, and providing on-demand usage data
- Deploying customer premise solutions to enable visibility and control of customer premise devices and resources in response to demand response, load control, and system reliability events.

Among the most common challenges faced by participants in successfully meeting their 2020 aspirations include:

- Lack of customer interest, engagement and willingness to participate in Smart Grid technologies
- Finding sufficient capital resources to invest in technologies with uncertain benefits
- Obtaining resources to successfully implement and maintain technologies
- Uncertainty of potential Smart Grid benefits
- Technology obsolescence and lifespan
- Cultural inertia and resistance to change
- Lack of information technology vision and planning and lack of understanding of the role of IT in Smart Grid
- Regulatory uncertainty
- Keeping up with evolving technologies and standards
- Managing conflicting goals and priorities among internal and external stakeholders

How can the Energy Commission Apply its Research Efforts to Help POU's Address these Challenges?

Additional Research is Needed to Reduce the Cost of Smart Grid Deployment

POUs commonly justify smart grid deployment on the basis of forecasted costs and benefits. To date, some POUs have estimated costs to be in excess of benefits and have consequently elected for costs to decline. Reductions in smart grid costs will increase deployment, especially at smaller utilities but it is not clear how much the costs have to decline to have a significant impact on the rate of deployment. Since the Energy Commission already invests in research to reduce the costs of technologies such as renewable energy and energy efficiency, it should consider conducting research into how the reducing the costs of advanced metering, distribution automation, energy storage and demand response may advance the impact of smart grid technologies on achieving energy policy objectives.

Additional Research is Needed to Identify the Smart Grid Impacts on Energy Policy

Although this report identifies specific ways that Smart Grid could positively affect California's energy policy goals, the progress in such accomplishments is currently unproven and there are no data to quantitatively measure progress. Over the course of the next few years, the Energy Commission should track and measure how Smart Grid is influencing key outcomes among POUs, such as:

- Reduce greenhouse gasses (GHG)
- Integrate rooftop solar panels
- Adhere to renewable portfolio standards
- Modify resource plans to first utilize energy efficiency, conservation and distributed resources

Extend Outreach for Smart Grid Education

Interviews with POUs identified Smart Grid education for boards, staff and consumers as a significant obstacle. POUs regularly survey their customers' interest in technologies for reducing energy consumption and reducing the environmental impact of electricity consumption, including perceptions of the potential costs and benefits of smart grid. POU customers are generally willing to accept that using smart grid technologies to accomplish 'good' things is something they would support but they are usually not interested in paying anything additional and are suspect as to the potential benefits. Whereas the Energy Commission has been involved in outreach to California's energy consumers about the positive impacts of energy efficiency and renewable energy, similar efforts could be applied to helping consumers understand the potential positive impacts that smart grid technologies may have toward meeting energy policy objectives. Particularly important areas for education could include: privacy and security, health impacts, reliability and the tangible financial benefits associated with smart grid technologies.

Encourage Customer Participation

One issue that confronts a successful Smart Grid launch is the role of customers. Many of the financial benefits that Smart Grid offers may not be fully realized if customers are not adequately engaged and participate on an on-going basis. Once the newness of the offering (such as, home area networks) has faded, customers might lose interest and revert to traditional behaviors.

Develop a Standardized Framework to Help POUs Quantify the Benefits and Costs Associated with Smart Grid

This will require a complex modeling approach and should include technology and customer programs such as DR modeled over a 15-year timeframe, at a minimum. It should be capable of modeling multiple Smart Grid applications simultaneously to understand a utilities entire Smart Grid return on investment and cash flow for budgeting and have the capability to quantify the financial implications of alternative strategies and to provide insights on the timing and integration of Smart Grid initiatives across the enterprises.

Continue to Track and Monitor POU Smart Grid Progress

Implementing the SGMM framework provided insight into the status of Smart Grid development at POUs. Since it is a measurement at a single point in time, tracking the POU's progress over time and timely success in achieving future aspirations, it is recommended that the Energy Commission support the application of SGMM at two-year intervals through the year 2020.

The SGMM is a powerful tool, yet has certain areas where refinement is recommended to track the unique needs and circumstances of POUs. Specific examples include survey question modifications to reflect POU governance (POUs are not regulated in the same manner as IOUs), concept of the utility's grid (the POU's grid is predominantly a distribution system, yet some SGMM questions pertain to the transmission or generation systems), and services (many POUs offer water and natural gas in addition to electricity – SGMM questions do not account for economies of scope that may be available by addressing multiple services).

Address Unique POU Challenges in Smart Grid Development

POU's face certain challenges that are significantly different from IOUs. Consequently, it is not surprising to find that the Energy Commission's role in promoting Smart Grid in the POU space needs to take into account a different set of challenges. Specific examples include size (POUs are commonly smaller than IOUs and therefore have fewer human resources to draw upon in implementing a Smart Grid program), financing (POUs' access to capital is significantly different from IOUs) and governance (POUs need to be responsive to an elected board which reflects the interests of its ratepayers).

Another challenge is that costs associated with many, necessary Smart Grid functions are not well scalable. Regardless of size, utilities are expected to require specialized expertise in cyber security, back-office support and software, communications and management. To a large extent, these features disadvantage smaller utilities (most notably POUs) and adversely affect the economic justification of Smart Grid. It is recommended that the Energy Commission support research into scaling Smart Grid systems to better fit smaller utilities.

Few POUs in California own and operate transmission systems (such as, IID, LADWP and SMUD) and the others rely on third parties (for example, joint agencies such as the Southern California Public Power Authority). One Smart Grid application that has received comparatively less attention in this research is transmission systems and sychrophasors. The role that non-transmission owners play in such areas is limited and should be explored more.

Engage California POUs in Smart Grid Evolution and Standards Development Processes

POUs should engage more with energy operators, technology providers and regulators to understand what standards are in place, and what the consequences of failing to meet those standards are. What new developments are on the horizon? How risk management and controls related to adoption of standards should be integrated into the entire Smart Grid project lifecycle? How they should apply technical, operational, and management controls according to best practices?

The Energy Commission should develop an ongoing discussion and interaction with the POUs in the State to engage them more in the standards development process by working with manufacturers and the Energy Commission to provide data and pilot demonstrations. Create a platform for information sharing and continued discussion between the POUs and the Energy Commission around enabling Smart Grid technologies and standards, the state of implementation of technologies, standards and pilot demonstrations, lessons learned, the evolving risks, impacts, and possibilities.

Continue Participating in Cyber Security and Data Privacy Issues

Smart Grid implementation in some California communities has raised questions about the security of utility networks and the privacy of customer data. Cyber security is a process and not an end-point. Therefore, POUs will need to make an ongoing investment in their IT processes and staff to ensure that adequate safeguards are in place and updated.

CHAPTER 8: Glossary

ACLM	Air Conditioning Load Management
AFM	Automated Feeder Management
ALW	Azusa Light and Water
AMI	Advanced Metering Infrastructure
AMP	Alameda Municipal Power
AMR	Advanced Meter Reading
AMS	Asset Management System
ANSI	American National Standard Institute
API	Application Programming Interface
APPA	American Public Power Association
APU	Anaheim Public Utilities
ARRA	American Recovery and Reinvestment Act
AS	Ancillary Services
Auto-DR	Automatic Demand Response
BPL	Broadband over Power Line
BRS	Broadband Radio Service
BWP	Burbank Water and Power
C&I	Commercial & Industrial
CAISO	California Independent System Operator
CARB	California Air Resources Board
CBM	Condition Based Maintenance
CDMA	Code Division Multiple Access
Energy Commission	California Energy Commission
CIM	Common Information Model
CIP	Critical Infrastructure Protection
CIS	Customer Information Systems

CMU	Carnegie Mellon University
CMUA	California Municipal Utilities Association
CO2	Carbon Dioxide
CPAU	City of Palo Alto Utilities
CPP	Critical Peak Pricing
CPUC	California Public Utilities Commission
CUST	Customer
CVR	Conservation Voltage Regulation
DER	Distributed Energy Resources
DG	Distributed Generation
DHS	Department of Homeland Security
DLC	Direct Load Control
DMS	Distribution Management System
DOE	Department of Energy
DR	Demand Response
DRMS	Demand Response Management System
DSSS	Direct Sequence Spread Spectrum
EA	Engineering Analysis
EBS	Educational Broadband Service
EE	Energy Efficiency
EEI	Edison Electric Institute
EIRP	Effective Isotropic Radiated Power
EISA	Energy Independence and Security Act
EMS	Energy Management Systems
EPRI	Electric Power Research Institute
ESB	Enterprise Service Bus
FCC	Federal Communications Commission
FCI	Fault Current Indicator

FERC	Federal Energy Regulatory Commission
FH-CDMA	Frequency Hopping Code Division Multiple Access
FHSS	Frequency Hopping Spread Spectrum
FiT	Feed-In Tariff
FLISR	Fault Location, Isolation and Service Restoration
GHG	Green House Gas
GIS	Geographical Information System
GO	Grid Operations
GPRS	General Packet Radio Service
GPS	Global Positioning System
GSM	Global System for Mobile Communications
GWP	Glendale Water and Power
HAN	Home Area Network
HEMS	Home Energy Management System
HPCC	HomePlug Command and Control
HVAC	Heating, Ventilation, and Air-Conditioning
ICS	Industrial Control Systems
IEC	International Electrotechnical Commission
IEDs	Intelligent Electronic Devices
IEEE	Institute of Electrical & Electronics Engineers
IHD	In-home Display
IID	Imperial Irrigation District
IMT	International Mobile Telecommunications
IOU	Investor Owned Utilities
IP	Internet Protocol
IRR	Internal Rate of Return
IS	Information Systems
ISO	Independent System Operator

IT	Information Technology
ITU	International Telecommunication Union
IVR	Interactive Voice Response
kbps	kilobits per second
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
LADWP	Los Angeles Department of Water and Power
LOB	Lines of Business
LTC	Load Tap Changer
LTE	Long Term Evolution
Mbps	Megabits Per Second
MDMS	Meter Data Management System
MHz	Megahertz
MVA	Megavolt Ampere
MW	Megawatt
MWFM	Mobile Workforce Management System
NAN	Neighborhood Area Network
NCPA	Northern California Power Agency
NESCO	National Electric Sector Cyber Security Organization
NESCOR	National Electric Sector Cyber Security Organization Resources
NERC	North American Electric Reliability Corporation
NETL	National Energy Technology Laboratory
NIST	National Institute of Standards and Technology
NISTIR	National Institute of Standards and Technology Interagency Report
NOx	Nitrogen Oxide
NPV	Net Present Value
NREL	National Renewable Energy Laboratory

O&M	Operations & Management
OFDM	Orthogonal Frequency-Division Multiplexing
OMS	Outage Management System
OS	Organization and Structure
PCTs	Programmable Communicating Thermostats
PEV	Plug-in Electric Vehicle
PIER	Public Interest Energy Research
PLC	Power Line Carrier
PLCs	Programmable Logic Controllers
POTS	Plain Old Telephone Service
POU	Publicly Owned Utilities or customer-owned public utilities
PMUs	Phasor Measurement Units
PTP	Point-to-Point
PVs	Photovoltaics
PWP	Pasadena Water and Power
R&D	Research & Development
RD&D	Research, development, and demonstration
REU	Redding Electric Utility
RF	Radio Frequency
ROI	Return on Investment
RPS	Renewable Portfolio Standard
RPU	Riverside Public Utilities
RTLF	Real-Time Load Flow
RTO	Regional Transmission Operator
RTP	Real-Time Pricing
RTUs	Remote Terminal Units
SAIC	Science Applications International Corporation
SAIDI	System Average Interruption Duration Index

SCADA	Supervisory Control and Data Acquisition
SCPPA	Southern California Public Power Authority
SE	Societal and Environmental
SEI	Software Engineering Institute
SGIG	Smart Grid Investment Grant
SGMM	Smart Grid Maturity Model
SMR	Strategy, Management, and Regulatory
SMS	Short Message Service
SMUD	Sacramento Municipal Utilities District
SOA	Service-Oriented Architecture
SOx	Sulphur Oxide
SVP	Silicon Valley Authority
T&D	Transmission and Distribution
TCP/IP	Transmission Control Protocol/Internet Protocol
TDMA	Time Division Multiple Access
TECH	Technology
TOU	Time-of-Use
U.S.	United States
UWB	Ultra Wideband
V2G	Vehicle-to-Grid
VAR	Volt-Ampere Reactive
VCI	Value Chain Integration
VVC	Volt-VAR Control
WAM	Work and Asset Management
WAN	Wide Area Network
WiMAX	Worldwide Interoperability for Microwave Access
WLAN	Wireless Local Area Network
WMS	Work Management System

APPENDIX A: California Smart Grid Initiatives Assessment Framework

Introduction

The information contained in this Appendix supplements Section 3 (California Smart Grid Initiatives Assessment Framework) with additional in-depth data and analysis.

Smart Grid Maturity Model

SGMM Benefits

Applying the SGMM process yields numerous benefits to POUs and this overall Project. Some of the key benefits include the development of an enterprise-wide Smart Grid vision and mission, active participation and coordination across numerous utility departments and setting objective and quantifiable steps to measurement progress.

Developing an Enterprise-wide Vision and Mission: Within California, there have been instances where application of the SGMM process directly resulted in a POU conducting its initial enterprise-wide facilitation and coordination of a Smart Grid assessment of its mission, vision or objectives. In practice, bringing widely diverse utility departments together to jointly review such attributes can be a daunting task. The Smart Grid related needs and objectives of different departments can, in some instances, appear to be in conflict. The SGMM process overcomes such obstacles by focusing the POU on matters of overarching importance (mission and vision) and specific ways (strategies) to achieving such ends.

Active Participation and Coordination: Smart Grid affects the day-to-day business operations of numerous POU departments (such as information technology, operations, customer service, and so forth). Moreover, successful implementation of Smart Grid (regardless of degree or nature of each POU's Smart Grid) demands active participation in the process. SGMM enhances the participation and coordination of affected POU stakeholders.

Objective and Quantifiable Measurements: The SGMM process objectively measures the status of Smart Grid implementation within numerous individual functional areas, as well as the overall POU.

SGMM Domains

An SGMM assessment provides a maturity rating for each of the model's eight domains. Domains are logical groupings of smart-grid related capabilities and characteristics. The model's eight domains are discussed below.

Strategy, Management, and Regulatory

The Strategy, Management, and Regulatory domain captures the fundamental question of whether the POU has determined its own unique Smart Grid goals and objectives. This includes the capabilities and characteristics that enable a POU to successfully develop its Smart Grid vision and strategy, establish internal governance and management processes, and promote collaborative relationships with stakeholders to implement that strategy and vision. POUs that are relatively mature in this domain have answered the key question of why the organization wishes to accomplish by utilizing Smart Grid. The integration, communication, and management of the mission, vision, and strategy guide a POU through its successful Smart Grid transformation.

As the Strategy, Management and Regulatory maturity level increases, the management processes across lines of business are increasingly consistent with, support and reflect the POU's Smart Grid vision and strategy. A higher level of maturity also indicates that internal Smart Grid leadership increasingly has explicit authority within the organization and with external stakeholders, including regulators, to implement the vision. Smart Grid modernization drives organizational strategy and direction, and new business opportunities will emerge that capitalize on the Smart Grid as a platform for the introduction of new services and product offerings.

Meetings with numerous POUs across the country find that the most common overarching objectives behind Smart Grid deployment focus on:

- Reduce the cost of electricity to consumers
- Improve the reliability of electricity supply
- Improve POU social and environmental responsiveness
- Respond to board directives

The objectives are not mutually exclusive and each POU is expected to chart its own course of action in achieving any subset of these objectives.

Organization and Structure

The Organization and Structure domain represents the organizational capabilities and characteristics that enable a POU to align and operate as required to achieve its desired Smart Grid transformation. These features are critical in understanding who are the POU's internal stakeholders and their individual and collective roles in achieving Smart Grid objectives. The domain focuses on changes in communications, culture, structure, training and education, and knowledge management within the organization. For grid modernization efforts to be successful, the POU's organizational structure must promote and reward cross-functional planning, design and operations. The organization must align its structure to take advantage of opportunities that a Smart Grid will provide.

Maturity within this domain reflects an increasing capability for the POU to move beyond reactive and compartmentalized decision making to planned, fact-based, and nimble decision making to achieve its Smart Grid goals. It also reflects a workforce whose competencies and skill sets are aligned with achieving the POU's Smart Grid vision.

Grid Operations

The Grid Operations domain represents the organizational capabilities and characteristics that support reliable, secure, safe, and efficient operation of the electrical grid. Increasing maturity within this domain reflects an evolution from relatively inflexible, manually intensive operations with limited visibility into the health of the grid to automated operations with significant flexibility and a high degree of situational awareness at local, regional, and national levels. POUs that have achieved a high level of maturity within this domain have an increased capability to use Smart Grid automation and information. They have the capability to manage power flows so that losses are minimized and the usage of lowest-cost generation resources (subject to renewable resource portfolio standards) are maximized. The answers to such questions illuminate how a POU will accomplish its Smart Grid objectives. The POU would increase its use of automation and the ability to see (monitor and measure) key aspects of the grid, decrease response times for communications and control, and reduce the likelihood of cascading system failures. These capabilities facilitate the goals of increasing grid reliability, security, efficiency, and safety. Additionally, it addresses broader grid modernization objectives such as improved power quality, empowering customers with choices among multiple generation options, optimizing the usage of grid assets, and operating efficiently.

Work and Asset Management

The Work and Asset Management domain represents the organizational capabilities and characteristics that support the management of human and physical assets that are required to meet the POU's Smart Grid objectives. It also addresses how a POU will accomplish its Smart Grid objectives. Increasing levels of maturity for this domain reflect an increasing capability of the POU to utilize information made available from the deployment of Smart Grid technologies.

One example of the objectives and value that may be associated with a mature Work and Asset Management implementation includes its ability to track the activities that would result in improvements in electric reliability. Potential Work and Asset Management outcomes include reduced maintenance and downtime, improved tracking of causes of failures, improved diagnosis of faults and recommend corrective actions, detection of failure conditions in advance of actual failures and a reduction in the time between problem identification and resolution. A second example objective could be a reduction in operating expenses. In this case, Work and Asset Management outcomes would include the ability to deploy workforce resources and physical assets more efficiently and improvements in capacity planning performance.

A POU that is mature in Work and Asset Management bases its equipment operation and maintenance decisions on up-to-date, fact-based performance data instead of on generic industry practices or broad, non-specific, historical precedents. Increasing maturity within this domain also reflects an evolution from preventative and reactive usage and deployment of resources to predictive and planned management. This supports the goals of increasing grid reliability, security, safety, and economic and technical efficiency.

Technology

The Technology domain represents the POU's capabilities and characteristics that enable effective strategic information technology planning for Smart Grid capabilities, and establishment of rigorous engineering and business processes for evaluation, acquisition, integration, and testing of new Smart Grid technology. The engineering and business processes should be based on the quality attributes necessary for achieving success and reducing risk (for example, interoperability, upgradability, security, safety, cost, and performance). POU's commonly address Technology concerns through their Information Technology (IT) departments. Organizational capabilities and characteristics in the Technology domain also reflect adherence to relevant industry and government standards, integration throughout the POU of optimized, data-rich Smart Grid applications and analytics (with extensive data sharing across lines of business and among industry partners). Use of the POU's Smart Grid IT infrastructure as a platform for creation and support of innovative business services generally focuses on how the POU can achieve smart-grid success.

Technology can contribute to or detract from a POU's ability to meet Smart Grid goals for itself, its customers, and for society at large. Smart Grid technology supports two-way digital communications, wide-area situational awareness (based on advanced sensor networks), and fine-grained control (such as, customer loads using smart meters and smart-grid-aware appliances). A cohesive technology strategy is necessary to connect and support Smart Grid data sources (including sensors), control elements, stakeholders and customers.

Customer

The Customer (CUST) domain represents the POU's capabilities and characteristics that enable customer participation and empowerment in achieving the benefits of Smart Grid. By focusing on the customer, the POU addresses who will capture Smart Grid benefits. The POU's customers or stakeholders include direct ratepayers (residences, commercial and industrial), its Board of Directors and pertinent regulatory agencies.

Customer participation may be passive (such as, allowing the POU to manage customer load and the selection of energy resources) or active (such as, providing customers with the advanced visibility and control needed to automatically manage their own load and choose among various energy sources, in response to pricing signals, available market options or preferences for renewable resources).

Utilities that demonstrate high levels of maturity in the Customer domain empower their customers to have the means to make and execute their own choices regarding the uses, sources, and cost of energy, while protecting the security of the grid and customer privacy. A high level of maturity in the Customer domain demonstrates organizational capabilities and characteristics that help a POU to meet utility, regional, and national goals with respect to energy efficiency, reduction of peak load, conservation, use of green energy resources, use of distributed generation, and reduced reliance on foreign energy resources (such as through innovative uses of the Smart Grid such as providing a customer management infrastructure and interface for plug-in electric vehicles).

Value Chain Integration

The Value Chain Integration domain represents the organizational capabilities and characteristics that determine how a POU will achieve its Smart Grid goals by successfully managing its organizational interdependencies within the supply chain for the production of electricity and the demand chain for its delivery. Value Chain Integration enables dynamic supply and demand management based on near real-time information. Traditionally, POUs were vertically integrated organizations typified by centralized decision-making and bounded by political geography. Automation extends beyond traditional POU departmental and geographic boundaries and touches upon the entire value chain to provide opportunities for innovation and efficiencies in load management, distributed generation and market structure. Increases in Value Chain Integration maturity are associated with improvements in inter-enterprise (such as, between the POU and its vendors) planning, implementation, and management of electricity from resources to end-use consumption. In general, such actions are expected to reduce the cost of electricity to the POU's customers.

Societal and Environmental

The Societal and Environmental domain represents the organizational capabilities and characteristics that enable a POU to contribute to achieving societal goals regarding the reliability, safety, and security of its electric power infrastructure, energy resources and the impacts of infrastructure and energy use on the environment. It addresses questions about why a POU launches a Smart Grid. SE issues are one of the salient issues in many POU Smart Grid initiatives. A smarter grid can enable a POU to make better informed choices and leverage energy alternatives while reducing environmental impacts. POUs can promote conservation and green initiatives by developing the ability to integrate alternative and distributed energy sources. Effective implementation of these programs can enhance the organization's reputation and strengthen relationships with its customers, board and the public at large.

Increased efficiencies in production and consumption made possible through a smarter grid not only reduce environmental impacts but can also sustain lower energy costs. POUs participating in Smart Grid deployments and operations can effectively address society's critical infrastructure protection concerns by incorporating security and resiliency solutions. The prevention, mitigation, and remediation of security risks and events are expected to be an ongoing requirement for the POU and its stakeholders.

Domain Summary

The preceding discussion notes that each domain serves a special purpose in measuring Smart Grid attributes. Grouping the above domains into the following categories is used later in this report to better illustrate POU's Smart Grid progress and areas that require additional consideration.

- Objectives: Why is the POU implementing Smart Grid? Motives are assessed by the Strategy, Management and Regulatory and Societal and Environmental domains.

- Methodology and Applications: How will the POU achieve Smart Grid objectives? Methods and applications are primarily addressed in the Grid Optimization, Work and Asset Management, Technology and Value Chain Integration domains.
- Stakeholders: Who are the POU's internal and external Smart Grid stakeholders? This question is examined in the Organization and Structure and Customer domains.

Each level of maturity within a domain builds upon the next, so a POU must achieve Level 1 prior to achieving Level 2, and so forth. Each level of maturity within a domain is fully described by a set of expected characteristics and a set of informative characteristics.

SGMM Assumptions

It is important to note the inherent issues that confront extrapolating results from a sample set of POUs to the entire population of POUs in California or electric utilities in general. First, the basis of this analysis is solely on surveyed POUs. This project did not call for applying the SGMM process to assess the maturity of Smart Grid at investor owned utilities or utilities located outside of California. Second, sampled POUs voluntarily participated in the SGMM assessment. In general, self-selected samples may result in potentially skewed results. Lastly, a sample size of 13 POUs, taken from a population of 45 total POUs in California, results in an error of approximately plus or minus 20 percent (assuming a confidence interval of 90 percent). Collectively, these points suggest that there is some uncertainty in predicting the Smart Grid maturity of all POUs in California.

SGMM Analysis of POUs

The maturity level for each domain is computed from the scores that each POU self-provided for 175 separate Smart Grid responses to questions. Responses were assumed to be accurate and no effort was made to independently verify the POUs responses.

There is an inherent assumption within the SGMM that a higher level of maturity is generally preferred to a lower level. This implies that, over time, the desired Smart Grid status of a POU is to strive to achieve a maturity level that is very high (such as, a 4 or a 5) in each of the eight domains. In practice, this may not (and perhaps should not) be the case. A POU might create a well defined vision of its year 2020 Smart Grid that addresses its own unique circumstances and intentionally targets a low or intermediate maturity level. The unique characteristics of each POU should be accommodated in setting its own vision and targets for each Smart Grid domain.

POU Rankings

The report identities the SGMM scores which are basis for ranking the POUs as being Followers, Fast Followers or Leaders. Rankings are based on a top-down perspective (as based on the POUs' cumulative Smart Grid maturity score) and a bottom-up perspective (as based on the maturity score of each domain). Each perspective is examined below.

Another top-down perspective applies the SGMM's lexicon to these data to facilitate labeling each category's domain as being one of the previously noted six maturity levels. In terms of increasing maturity, the six levels are Status Quo, Initiator, Integrator, Optimizer and Pioneer. The following table summarizes the results of this exercise.

Table A-1: Domain Levels by POU Category

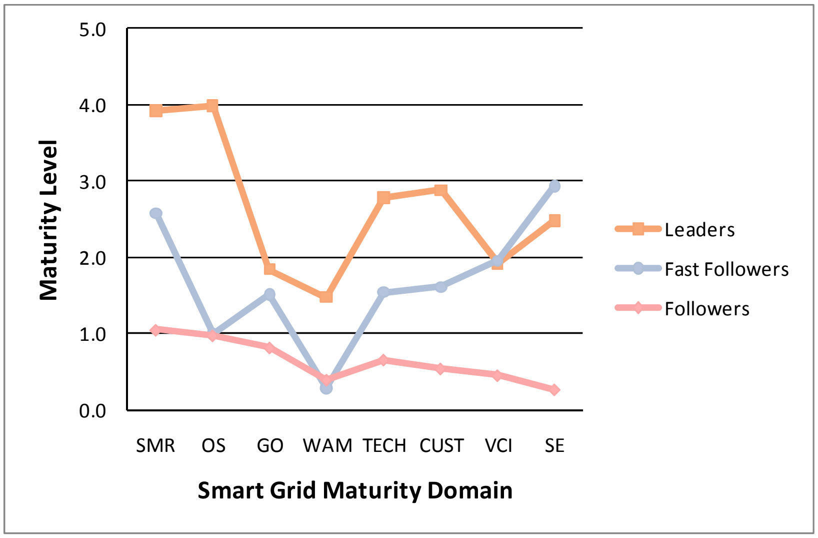
Domain	Follower	Fast Follower	Leader
SMR	Initiator	Integrator	Optimizer
OS	Initiator	Initiator	Optimizer
GO	Initiator	Initiator	Enabler
WAM	Status Quo	Status Quo	Initiator
TECH	Initiator	Initiator	Integrator
CUST	Status Quo	Initiator	Integrator
VCI	Status Quo	Enabler	Enabler
SE	Initiator	Integrator	Enabler

SMR: Strategy, Management, and Regulatory Domain
OS: Organization and Structure Domain
GO: Grid Operations Domain
WAM: Work and Asset Management Domain
TECH: Technology Domain
CUST: Customer Domain
VCI: Value Chain Integration Domain
SE: Societal and Environmental Domain

Bottom-Down Perspective

Augmenting the above top-down approach with a bottom-up perspective provides a second test to confirm the above categories and is useful in identifying patterns in the domain level characteristics of each category. The following figure depicts the Smart Grid maturity level for each domain for Followers, Fast Followers and Leaders.

Figure A-1: Smart Grid Maturity for Followers, Fast Followers and Leaders



SMR:	Strategy, Management, and Regulatory Domain
OS:	Organization and Structure Domain
GO:	Grid Operations Domain
WAM:	Work and Asset Management Domain
TECH:	Technology Domain
CUST:	Customer Domain
VCI:	Value Chain Integration Domain
SE:	Societal and Environmental Domain

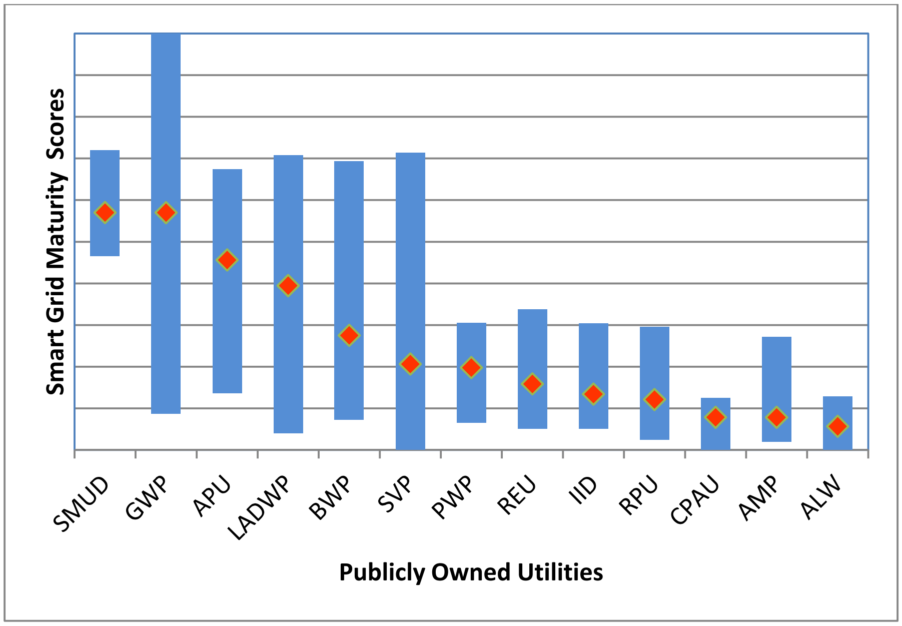
These data indicate that differences between the three categories cut across nearly all of the Smart Grid domains. Maturity scores for the POUs that comprise the Follower category are noticeably lower than Fast Followers and Leaders. Domain levels for Followers range between 0 and 1, indicating an Initiator status within the SGMM framework. The primary characteristics of Followers are that they track the progress of Smart Grid at other POUs, especially Leaders, and monitor the overall state of the industry. Followers are generally not enabling or implementing features within a domain that are necessary to achieve grid modernization. They are also not establishing specific Smart Grid budgets, integrating or deploying Smart Grid in any of the measured domains.

Variability in POU Scores

The Energy Commission is tasked with searching for catalysts to promote POUs' adoption of Smart Grid as a means to achieving California's energy policy objectives. This outlook requires care in avoiding one particular omission: Smart Grid is not a singular task whereby utilities would uniformly achieve it or not. Instead, Smart Grid is composed of numerous features and applications, which the SGMM has categorized as eight separate domains. The case must be made for some degree of progress in all domains, not just a few, to fully capture the benefits that are aligned with the state's energy policy objectives. To illustrate, if a POU's maturity scores were a "5" (Pioneer) in half of the Smart Grid domains and a "0" (Status Quo) in the other half, the cumulative score might be a sufficient to label that POU as a "Leader", yet its ability to accomplish energy policy objectives would probably be severely lacking. Consequently, it is important to examine the variability in Smart Grid maturity scores across the eight domains to identify areas of potential concern and potential patterns that would need to be addressed in the Smart Grid roadmap.

The variation in maturity scores is shown graphically in the following figure, which depicts the minimum, maximum and average scores for each POU.

Figure A-2: Range and Average Smart Grid Maturity Scores by POU



ALW:	Azusa Light & Water	LADWP:	Los Angeles Water and Power
AMP:	Alameda Municipal Utility Power	PWP:	Pasadena Water and Power
APU:	Anaheim Public Utility	REU:	Redding Electric Utility
BWP:	Burbank Water and Power	RPU:	Riverside Public Utilities
CPAU:	City of Palo Alto Utilities	SMUD:	Sacramento Municipal Utility District
GWP:	Glendale Water and Power	SVP:	Silicon Valley Power
IID:	Imperial Irrigation District		

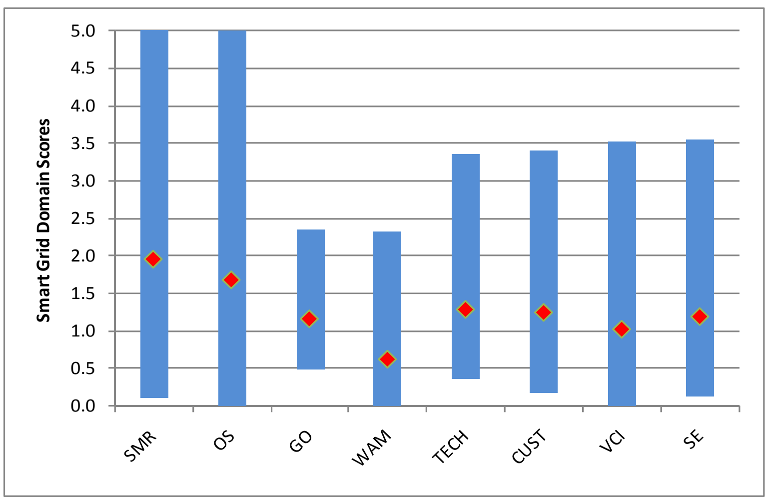
The above figure shows that the degree of variability in maturity scores is generally proportional to the maturity of the POU's Smart Grid. POUs that are more mature overall (as measured by the average of its SGMM domain scores) display greater variability in domain maturity than POUs that are less mature. This can be explained by two factors. First, while certain POUs have made considerable advancements in specific Smart Grid domains, progress is not necessarily uniform across the entire enterprise. To some degree, this is intentional. There are important advantages in completing a substantial amount of planning before implementing a Smart Grid program, which in turn causes some domains to be more mature and earlier than others. For example, it is advantageous to develop and communicate Smart Grid vision and mission statements across the entire POU (including its Board of Directors) prior to making IT purchasing decisions. As such, the SMR domain, which focuses on vision and mission, should be more mature than domains that emphasize operational considerations. The data does in fact support this hypothesis, finding that the average SMR maturity score (which are generally more planning oriented) across all interviewed POUs is 1.95, while the average maturity score for more operational domains (WAM, TECH, CUST and VCI) is only 1.04.

A second explanation for the variability in maturity scores comes from the POUs' overall outlook regarding Smart Grid. Discussions during the SGMM interviews indicated that certain POUs are generally very cautious about Smart Grid and that this perspective has affected all departments, resulting in low maturity scores across all domains. The data shown in the above figure supports this conclusion, as seven of the 13 POUs reflect a narrow range and comparatively low maturity scores.

In addition to variability in POU maturity scores, domain scores are also vary widely. The following figure depicts the minimum, maximum and average scores for each of the eight Smart Grid domains. SMR and OS domain scores nearly span the entire spectrum, from being a Pioneer (demonstrating a comprehensive approach to setting and communicating vision, mission and strategies) to a low level Status Quo (indicating that vision and strategies have not been formulated or communicated). These data suggest that while some POUs have taken a rigorous approach to developing Smart Grid visions, strategies and alignment of internal organizational structures, others have not. This is significant since Smart Grid adoption should commence with a well thought out vision, strategy and understanding of how the organization will be affected by Smart Grid.

The lesson that can be learned from these data may be that Smart Grid adoption could be promoted within California POUs by providing assistance or guidance in such fundamental tasks.

Figure A-3: Range and Average Smart Grid Maturity Scores by Domain



SMR:	Strategy, Management, and Regulatory Domain	TECH:	Technology Domain
OS:	Organization and Structure Domain	CUST:	Customer Domain
GO:	Grid Operations Domain	VCI:	Value Chain Integration Domain
WAM:	Work and Asset Management Domain	SE:	Societal and Environmental Domain

Two domains (GO and WAM) are noticeably lagging behind SMR and OS and reflect a much narrower range of measured maturity scores. Our interpretation of these data is that the POU space is relatively unanimous in its lack of progress in making Smart Grid truly operational.

Pilot programs are planned or are in-progress at some POUs, but few, if any, have been completed. As Smart Grid adoption grows over time, these two domains are expected to advance as Smart Grid plans gradually turn into reality.

Potential actions by the Energy Commission are to promote GO and WAM progress include the development of technology roadmaps, such as the one described in this report, and industry seminars to provide training in grid operations and optimal asset management.

The last four domains (TECH, CUST, VCI and SE) scored in line with each other and indicate that POUs range from Status Quo to Integrating. One explanation for domain variability was discovered during the face-to-face interview process. In practice, some California POUs have internal champions that are driving progress within their own departments, but have little or no impact on other departments. This is especially pronounced in the TECH domain.

APPENDIX B: Smart Grid Project Descriptions of ARRA Grant Recipients

APU Smart Grid Project

Customer Service & Demand Management and Response

APU's Smart Grid project includes smart meters, communications infrastructure, time-based rate programs, and advanced customer service options.

Communication infrastructure includes an advanced communication network and leverages public wireless networks available.

Advanced Metering Infrastructure includes a city-wide deployment of smart meters. The head end server will manage two-way data transactions for residential and commercial & industrial customers.

Meter Data Management System will connect to a web portal for customers to view their water and energy consumption and will be integrated with APU's customer billing system. Additionally, the OMS will also be integrated with the MDMS.

Advanced electricity service options will include enrolling customers to receive programmable communicating thermostats (PCTs) that assist in managing electricity use and costs. These activities allow the APU to manage, measure, and verify targeted demand reductions during peak periods.

Grid Automation & Management

APU's Smart Grid project involves an expansion of distribution automation capabilities, which include circuit switches, remote fault indicators, and smart relays. The DA devices will be remotely monitored & controlled via SCADA. The new distribution automation technologies will improve service quality and reliability by enabling improved outage management, distribution circuit monitoring, and automated circuit switching.

In addition to the ARRA funded Smart Grid initiatives, a "complete" automation of its distribution circuits is in the full vision of APU's Smart Grid. Per APU's Smart Grid Deployment Plan filed with the Energy Commission, supporting projects for this vision include the following.

- **System Protection Upgrades:** This project will replace old electromechanical, solid state, and first generation digital relays with new microprocessor based relays which offer increased functionality, precision, reliability, and efficiency over the older relays. These new relays will be the backbone and primary "decision maker" for Smart Grid applications related to system reliability and control.

- **Substation Automation:** This project will remove the old substation remote terminal units (RTUs) from service and integrate the new microprocessor relays, meters, and other intelligent devices that are being installed at the substations. The utilization of these devices will dramatically reduce the amount of wiring, troubleshooting, and maintenance required to place new alarm, control, and telemetry points onto the SCADA system.

- **Packet Radio Network Expansion:** The Packet Radio network is the backbone communication method for all automation and some AMI projects. This network utilizes a 900MHz spread spectrum, un-licensed mesh technology. The system uses "hop" radios to route or pass data from the end device to a head end or master station radio. The expansion of the packet radio network is required to keep pace with all automation and Smart Grid projects (applications) to maintain the performance (speed) of remote control and monitoring the automation equipment.

- **SCADA Fiber Optic Network Expansion:** This network is used with underground automation equipment where radio communication is not possible or degraded. A SCADA fiber optic network is already installed, generally throughout the area of concern. However, the fiber optic cable will be installed from two different local substations to provide backbone reliability and failover capability. One or more SCADA fiber optic cabinets are installed in the area with substation class gateways (or concentrators) that will communicate with the automation equipment and send the data to the appropriate Substation Automation system(s). These installations will provide extremely fast and reliable communication to the 11 automation equipment and can be expanded and/or utilized for any Smart Grid applications in the same area.

- **Cyber Security Improvements**: This project is required to implement new NERC cyber security requirements, per CIP 003-009 as well as Department of Energy driven NIST standards even if the City is not required to do so currently. This project will provide for the City to be in complete compliance with CIP 003 – 009 standards and the DOE NIST requirements.

- **Switch Automation:** This project provides for the engineering, design, and installation of motor operated and other control equipment onto overhead and underground distribution and sub-transmission level switches. Electric System Operators at the Control Center will be able to remotely control and monitor these switches via the SCADA system. These switches will dramatically reduce the amount of time customers are without power during circuit interruptions as well as provide increased flexibility during routine switching. Switch automation projects (both overhead and underground) will provide the ground floor for most of the Smart Grid reliability focused applications.

- **Capacitor Bank Automation:** This project provides for the engineering, design, and installation of remote controlled distribution capacitor banks to reduce the reactive power flowing on a circuit and/or boost the voltage at a location on a circuit. The automation of capacitor bank switching will coordinate the switching of the capacitor banks along a circuit, as well as the capacitor banks installed at each 12 substation. Several Smart Grid applications will rely on remote capacitor bank switching.

Distributed Energy Resources & Distributed Generation

APU's ARRA funded Smart Grid project does not include integration of DER/DG resources such as energy storage technologies or plug-in vehicles. However, per APU's Smart Grid Deployment Plan filed with the Energy Commission, integration of DG resources and remote control of these resources will be enabled as part of APU's Smart Grid initiatives. As stated in its plan, APU is planning to utilize locally installed small generators and renewable resources to offset circuit loading at the substations and the grid. APU will switch on these small sources of energy to aggregately relieve feeder loading and to prevent rolling blackouts (grid wise load reduction) or circuit overloading. APU will enable remote control of renewable energy sources to further add the benefit of switching on zero emission sources when needed.

BWP Smart Grid Project

Customer Service & Demand Management and Response

BWP's Smart Grid project includes smart meters, communications infrastructure, time-based rate programs, advanced customer service options and demand response. The project implements two-way communications and metering to enable customers to view their energy consumption at their convenience through systems such as Web portals. The project includes installation of following equipment and systems:

- 52,257 Smart Meters
- AMI Communication Systems
  - Meter Communications Network
  - Backhaul Communications
- Meter Data Management System
- Approx. 5,000 In-Home Displays / Energy Management Systems
- Approx. 5,000 Programmable Communicating Thermostats
- 280 Thermal Energy Storage Units – Ice Bears
  - Time-Based Rate Programs (Under Consideration):
  - Time of Use
  - Time of Use (for Vehicle Charging)
  - Critical Peak Pricing

Communications infrastructure includes a fiber optic network and a city-wide secure Wi-Fi mesh radio frequency network. Radio devices in smart meters transmit data through a new Wi-Fi network. Home area networks provide two-way communication between BWP and customers and enable demand response and advanced electric service options.

Advanced metering infrastructure includes smart meters for all 52,257 residential, commercial, and industrial customers. New AMI features such as outage notification and remote service switches enable BWP to respond to outages and customer requests quickly and efficiently. AMI enables time-based rate programs and electric service options for customers. BWP expects lower operational costs from remote meter reading and more frequent identification of electricity theft.

Meter Data Management System will be installed and integrated with AMI, CIS and OMS. The new MDMS use data and notifications from smart meters and automated distribution equipment

Customer Energy Portal will be installed to provide on-line feedback on customer electricity consumption through energy usage reporting programs.

Time-based rate programs that are under consideration include time-of-use pricing, critical peak pricing, and related information services in conjunction with advanced metering to encourage consumers to shift their energy consumption from on- to off-peak periods.

Advanced electricity service options, in conjunction with time-based rate programs, will enable customers to monitor and better control electricity use. Programmable communicating thermostats allow customers to better manage their air conditioning and heating costs. In addition, BWP is planning to demonstrate in-home and in-business displays for customers who volunteer to receive this type of information feedback.

Energy Demand Management System will be installed for demand-side management of customer energy consumption including controllable load and distributed energy resources.

Grid Automation & Management

BWP's Smart Grid project includes installation of distribution automation devices and technologies to enhance the reliability and quality of electric delivery and reduce operations and maintenance costs. The project includes installation of following equipment and systems:

- Distribution Automation Equipment for 106 out of 117 Circuits
- Distribution Management System
- Automated Distribution Circuit Switches
- Distribution Automation Communications Network

Distribution automation systems include automated reclosers on 106 circuits, and demonstration of automated feeder switches, capacitor banks, and fault indicators on select circuits in BWP's service territory. Distribution automation is being used to help integrate distributed energy resources. The project also includes building an Integrated Systems Model (ISM) of BWP's 12kV system, reconfiguration of the 12-kV system with automatic operated sectionalize switches to reduce outage durations, and installation of automatic circuit reclosers on all 4-kV circuits. The ISM will initially be utilized to analyze and design the optimum configuration and placement of the automated sectionalize switches for the BWP DA scheme and then will be utilized in real-time as the analysis engine to monitor system conditions for remote feeder sectionalizing, fault detection and substation/voltage monitoring. The ISM will be integrated with SCADA, GIS and MDMS to operate the system more efficiently and perform analysis for system optimization.

BWP is also undertaking implementation of other technologies and/or programs as part of its distribution automation and management efforts. These technologies / programs are:

- **Mission Critical Asset Protection Program:** Establish security for all BWP mission critical and essential assets. Includes CIP standards documentation, Energy Control Center and Ethernet Switch Services Network (ECC/ESSN) security, and Smart Grid security
- **Outage Management System (OMS)** Integration with Smart Grid infrastructure and MDMS to feed outage data into the OMS in near real-time. The new OMS use data and notifications from smart meters and automated distribution equipment. Also includes installation of an Interactive Voice Recording (IVR) system to process customer calls.
- **AMI meter installation for distribution transformer monitoring:** Includes installation of one AMI meter for each of BWP's 5,700 distribution transformers. These meters will enable operators to observe operational status of all distribution transformers. These meters will be integrated with the MDMS. Integration of outage events generated by these meters into the OMS will greatly improve BWP's outage response activities by pinpointing affected fault isolating devices, prioritizing automated or manual restoration processes, and directing service repair and restoration personnel to specific work sites.

Distributed Energy Resources & Distributed Generation

BWP's Smart Grid project includes controls for distributed energy resources to manage peak electric demand and integrate renewable resources into grid operations. The project includes installation of following equipment and systems:

- **15 Electric Vehicle Charging Stations:** Provide convenient charging capabilities for plug-in electric vehicles. The stations use smart meters to track vehicle charging patterns and costs.
- **DER interface and control systems:** Include deployment of 280 thermal energy storage units (Ice Bear units) which represent approximately 2 MW of thermal energy, in conjunction with 100 KW of customer-owned concentrated photovoltaics(PVs) not funded by the project, with grid operator controlled power inverter technology. The

inverter technology enables electric system operators to provide voltage regulation, and control active and reactive power output.

GWP Smart Grid Project

Customer Service & Demand Management and Response

GWP's Smart Grid project includes system-wide deployment of advanced meters, use of customer systems and in-home displays to reduce peak loads, overall electricity use, and operations and maintenance costs. The project implements secure wireless communications to (1) allow customers to view their electricity consumption through Web portals and displays at any time, and (2) allow GWP to manage, measure, and verify targeted demand reduction during peak periods. The project includes installation of following equipment and systems:

- 120,000 Smart Meters
- AMI Communication Systems
- Meter Communications Network
- Backhaul Communications
- Meter Data Management System
- Up to 80,000 Home Area Networks
- Customer Web Portal Access for 80,000 Customers
- Up to 30,000 In-Home Displays
- 1.5 MW of Distributed Energy Storage Devices
- Time-Based Rate Programs Targeting up to 80,000 Customers
- Time of Use
- Critical Peak Pricing

Communications infrastructure includes an Ethernet/Internet protocol backhaul and a local wireless radio frequency network that enables two-way communication between meters and utility data systems. Data management systems enable GWP to develop actionable information from equipment notifications and customer electricity usage data.

Advanced metering infrastructure includes deployment of 120,000 smart meters (88,000 electric and 32,000 water meters). These meters provide the capability for a variety of current and future customer electricity price and service options and reduce GWP's costs of electricity delivery. New AMI features such as outage and restoration notification and a remote service switch enable GWP to respond to outages and customer requests more efficiently.

Meter Data Management System will be installed and integrated with AMI, CIS, DMS/OMS, and other operational systems through an enterprise service bus.

Time-based rate programs include time-of-use and critical peak pricing programs. GWP expects customers participating in these programs to reduce peak demand or shift consumptions from peak- to off-peak periods, which can reduce overall electricity costs.

Advanced electricity service options include in-home displays and Web portals facilitating two-way information exchange, providing the ability for customers to view their consumption and manage their bills.

Grid Automation & Management

GWP's Smart Grid project includes installation of distribution automation equipment systems, and management of distributed energy storage. The project aims to reduce operations and maintenance costs while increasing distribution system efficiency and reliability. GWP is upgrading selected feeders with distribution automation equipment. The project includes installation of distribution automation pilot for 4 feeders with full implementation of remaining feeders starting in FY 2013-2014:

- Distribution Management Systems
- DA Communications Network
- Automated Capacitors
- Equipment Health Sensors
- Circuit Monitors/Indicators
- Automated feeder/reclosers/ fault / interrupters
- Disturbance monitoring relays
- Smart protective relays

Distribution automation systems include the demonstration of automated feeder switches, feeder monitors, remote fault indicators, and automated capacitor controls on select feeders. The DA devices are using the AMI communications infrastructure to detect and isolate outages to minimize the number of customers affected and duration of the outage. Additionally, these devices are being implemented in conjunction with a distribution management system (DMS), a load management system, and an outage management system (OMS). The combination of the distribution automation devices and the enterprise applications enables GWP to improve distribution loading conditions and system reliability.

Distribution system energy efficiency improvements involve the integration of automated capacitor with a power quality monitoring system. The capacitors improve voltage and volt ampere reactive (VAR) control, power quality, and distribution capacity by reducing energy losses on the distribution system.

GWP is also undertaking implementation of enterprise computer systems as part of its distribution automation and management efforts. These systems include implementation of an Enterprise Service Bus (ESB), GIS, Asset Management System (AMS), OMS, Transformer Information Load Management System (TILM), Load Forecasting System (LFS), Load Management System (LMS) & Mobile Workforce Management System (MWFM).

Distributed Energy Resources & Distributed Generation

GWP's Smart Grid project includes controls for distributed energy resources to manage peak electric demand and integrate renewable resources into grid operations. The project includes installation of following equipment and systems:

- **Electrical Vehicle Charging Stations:** To understand and manage the effects of increased loading on the distribution system. The charging stations provide GWP with information necessary to develop electricity service options and pricing programs for customers with electric vehicles.
- **Enterprise Computer Systems :** Electric Vehicle Management (EVM) system.
- **DER interface and control systems:** Involve information systems for managing peak load and energy costs for 214 thermal energy storage units (Ice Bear units), which represent approximately 1.5 MW thermal energy.

LADWP Smart Grid Project

Customer Service & Demand Management and Response

LADWP is collaborating with a consortium of research institutions to develop new Smart Grid technologies, quantify costs and benefits, validate new models, and create prototypes to be adapted nationally. The project includes following initiatives:

- **Demand Response:** An integrated demonstration of Smart Grid operations and technology as applied to demand response will investigate a full range of user environments: residential, commercial, light industrial, and institutional.
- **Customer Behavior:** A comprehensive portfolio of studies and focused surveys related to the impact of Smart Grid communications systems and processes on customer usage; energy savings from using Smart Grid enabled interfaces; pricing options and programs; and effective messaging and incentives regarding electric vehicles.

However, apart from the Smart Grid demonstration project LADWP has an extensive ten year investment plan that includes following strategic initiatives:

- **AMI Metering Initiative:** Includes installation of a hybrid advanced meter reading (AMR) and AMI metering solution. LADWP is in the process of installing:
    - Water AMR meters with one-way communication capability using RF technology for walk by meter reading

  - Electric AMI meters with two-way communication capability using cellular technology for meter reading of large commercial and a limited number of residential customers (7 percent of customer base)
  - Electric AMR meters with one-way communication capability using RF technology for walk by meter reading of small commercial and residential customers (93 percent of customer base).
  - Home Area networks for a limited number of customers

- **Demand Response Initiative:** LADWP had a Demand Response rate for years for large industrial users. Currently, there are 30 Megawatts of interruptible load. Participation to the program is voluntary. LADWP is evaluating various residential load aggregation technologies that will provide an option of demand response participation to residential customers.

- **System and Data Integration Initiative:** LADWP is working on integrating the MDMS, OMS, and CIS with various web services. These services will be designed to provide accurate and timely information to customers regarding their consumption, billing, any pending outages and restoration statuses. The customers will have the option to adjust their accounts to set up their profile and notification preferences.

Once these initiatives are completed, the full functionality of LADWP's Smart Grid will include the following aspects:

- Outage Notifications
- Automatic Meter Reading
- Load Control of residential and commercial devices
- Other applications as they become available.

Grid Automation & Management

LADWP's Smart Grid project includes demonstration of next-generation cyber security technologies to show grid resilience against physical and cyber-attack, an operational testing approach for components & installed systems, and redefine the security perimeter to address Smart Grid technologies.

However, apart from the Smart Grid demonstration project LADWP has an extensive ten year investment plan that includes following strategic initiatives:

- **Transmission Automation Initiative:** For years, LADWP has worked in substations to meter the transmission lines and record PMU measurements used to determine the health of the electrical system. LADWP will install PMUs, and upgrade tie-line meters to improve measurement, provide backup metering at tie points, collect dynamic reads, and reroute power. The real-time data provided by PMU will be used for predicting instability in the transmission system and undertaking preventive actions.

- **Substation Automation Initiative:** For the past five years, LADWP has implemented a comprehensive program to install a new Power System Substation Automation System (SAS) from the Energy Control Center (ECC) to the substations, transmission, and generation stations. Currently, 80 of the approximate 200 substations and generation stations have been updated to the new SAS, and a new SCADA system has been implemented. There are approximately 70 more stations in the inventory that will be implemented over the next two to three years. Approximately 840 feeders now have remotely controlled circuit breakers and remote monitoring of megawatt loading of wire/cables. A significant amount of data is already being processed through the SCADA system and is available to the load dispatchers and other personnel on an as needed basis. At the conclusion of this project, the vast majority of feeders at all substations will be observable and controllable from the ECC.
- **Distribution Automation Initiative:** There have been several pilot projects for the DA relating to devices outside the substation walls (Current's Broadband over Power Line project, Ricochet Spread Spectrum project, and Telemetric Cellular project). LADWP is currently evaluating fault indicators, remotely controlled switches and automatic capacitor banks. These devices can be used for dynamic optimization of the distribution system.
- **Communications Initiative:** Over the past ten years, thousands of miles of fiber optic cable has been installed in over 72 substations as part of a fiber optic broadband infrastructure. The plan is for all substations to have fiber optic connections within the next two years. LADWP evaluates different communication protocols that can be used for the real-time control and observation of deployed automation equipment.
- **System and Data Integration Initiative:** Significant progress has been made in the power system in implementing the best of breed systems. The systems that are the backbone of the business and information processes in the power system are: work management system (WMS – mobile enabled), maintenance asset management systems (mobile enabled), geospatial electrical system (mobile enabled), outage management system (mobile enabled), and ECS/Historian. Significant integration between these and the corporate systems is in place. LADWP also purchased and installed OSIsoft's Pi Historian as a fast real time data processing system. The next Pi Historian initiative is to use it as a central repository for all of LADWP's real-time data and to allow access to the appropriate users of the data throughout the utility. LADWP has currently installed the Pi Historian in two locations (ECC and JFB) with a tag count of 20,000 data points. There are three pilot Pi Historian applications running at this time: 1) door/gate alarm; 2) Operation logger; and 3) Power System Dashboard real time data. Five user groups (Reliability, Planning, Station Operators, Grid Operations, and Meter) are also currently developing new applications.
- **Cyber Security Initiative:** The implementation of Smart Grid will involve a wide deployment of smart remotely controlled network capable devices which can be

potential points of cyber attack due to network connectivity. Due to the importance of cyber security, three key items will be developed:

- Grid resilience effort will show how the Smart Grid can operate resiliently against physical and cyber attack.
- Operational effectiveness effort will demonstrate a complete cyber security testing approach for components and installed systems.
- Redefinition of security perimeter effort will demonstrate new cyber security measures that address the expansion of this perimeter by Smart Grid technologies to the meter in residential and commercial sites.

Once these initiatives are completed, the full functionality of LADWP's Smart Grid will include all of the following aspects:

- Outage Notifications
- Transformer Monitoring
- Capacitor Controls
- Line Switch Controls
- Video Surveillance via Smart Grid
- Fault Management
- Transformer Deterioration
- Transformer Overloading
- Current Monitoring
- Cable Management
- Surge Protection
- Lighting Controls
- Weather
- Municipal Applications
- Other applications as they become available.

Distributed Energy Resources & Distributed Generation

LADWP's Smart Grid project includes a demonstration of electric vehicle integration into the LADWP grid to demonstrate aspects such as smart charging and battery aggregation; renewables and EV battery integration; an operational microgrid; and EV test bed sites at USC and UCLA.

However, apart from the Smart Grid demonstration project LADWP has an extensive ten year investment plan that includes following strategic initiatives:

- **Renewable Integration:** LADWP has a comprehensive Integrated Resource Plan (IRP) where new wind, solar, and geothermal power plants, as well as energy storage, and electric vehicles will be incorporated into the power generation mix. Currently, the ECS/Historian Servers have been installed at Pine Tree Generation Station, and there are plans to install more of these servers at each of the power plants. These servers allow for real-time monitoring and control of renewable sources, which will be equipped with automation equipment to facilitate peak shaving activities and to better support the adoption and utilization of renewables.
- **Feed-In Tariff (FiT) Initiative:** FiT seeks to purchase energy from small and medium-scale renewable energy projects (from 30 kilowatts up to one megawatt in AC capacity) within the service territory of LADWP under a long-term Standard Offer Power Purchase Agreements (SOPPA). The SOPPA terms are standard for all participants, can be up to 20 years in duration, and participants will be paid the bid base price of energy plus Time-of-Delivery (TOD) multipliers. FIT is a distributed generation (DG) program designed for the local Los Angeles market, and gives LADWP customers the opportunity to sell energy to LADWP from using their property as the DG site.
- **Solar Incentives Program:** The LADWP Solar Photovoltaic Incentive Program provides financial incentives to LADWP customers who purchase and install their own solar power systems. LADWP currently also provides an additional incentive payment for systems using PV modules manufactured in the City of Los Angeles. LADWP currently provides a Los Angeles Manufacturing Credit (LAMC) for qualifying photovoltaic equipment manufactured in Los Angeles as approved by the LADWP guidelines. The goal of the LAMC is to promote local economic development through manufacturing and job creation within the City of Los Angeles and to reduce costs through increased volume and competition.

SMUD Smart Grid Project

Customer Service & Demand Management and Response

SMUD's Smart Sacramento Project involves system-wide deployment of an advanced metering system integrated with existing enterprise and information technology systems. The project also involves customer systems that provide usage and cost information to customers that educate and enable more control over their consumption. The project includes installation of following equipment and systems:

- Approximately 600,000 Smart Meters
- AMI Communication Systems
- Meter Communications Network

- Backhaul Communications
  - Meter Data Management System
  - Customer Web Portals
  - Customer Systems for up to 10,000 Customers
- Home Area Networks
- In Home Displays/Energy Management Systems
- Programmable Communicating Thermostats
- Direct Load Control Devices
  - Demand Response Management System
  - Time-Variant Pricing Programs
  - Time of Use
  - Critical Peak Pricing

Communication infrastructure includes wireless systems that provide two-way communication for smart meters, customer devices, and distribution automation equipment. A new backhaul communications network, meter data relay network, and front-end data management system are being deployed throughout the SMUD service territory. Software platforms for meter data management and analysis are being installed to organize, integrate, summarize, and make data accessible from the smart meters. These systems provide SMUD with expanded capabilities to link customer information, electric distribution operations, and system-level reliability information.

Advanced metering infrastructure includes the deployment of approximately 600,000 smart meters covering SMUD's entire service territory. This system provides automated meter reading, improved meter accuracy, enhanced outage response and notification, and improved theft detection.

Meter Data Management System will be used as the "system of record" for meter reading data. MDMS will be integrated with AMI and SAP to complete the meter to bill process for SMUD customers.

Demand Response Management System will be the platform for communicating with programmable communicating thermostats (PCTs), home energy management systems (HEMs) and building automation systems. The demand response management system (DRMS) will be sufficiently flexible to accommodate a wide range of dynamic pricing and load control options, and be expandable to integrate future Smart Grid applications (such as distributed automation, smart appliances, and management of distributed resources). SMUD will employ an aggressive marketing and education campaign to encourage the 100,000 customers currently participating in SMUD's Air Conditioning Load Management (ACLM) program to migrate from one-way switch technology to two-way PCTs or HEMs that are direct load controlled and dynamic pricing enabled. In addition, additional residential and small commercial customers will be encouraged to participate in the program via PCTs or HEMs. SMUD plans on having PCTs, HEMs and other smart controls deployed to 50,000 of its residential and small commercial customers (about 10 percent of SMUD's customers) and to fully link these customers to the DRMS. SMUD will also develop and implement an automatic demand response (Auto-DR) option for medium and large commercial customers. Participating customers will be placed on a dynamic rate. Development and implementation of Auto-DR options will be closely integrated with the voluntary dynamic pricing programs implemented under. Auto-DR resources will be linked to the DRMS.

Time-based rate programs include time of use, critical peak pricing, and time of use with critical peak pricing. Customers with smart meters selected to receive the new program rates can keep their existing rates or enroll in the new program. The aim is to evaluate the relative merits of these programs in terms of load impacts, customer acceptance, and cost effectiveness. SMUD expects to provide customers with greater control over their electricity bills and limit capital investment and emissions that result from adding peak generation capacity.

Advanced electricity service options include enhanced Web portal services and tools for customer information and energy management, control, and automation; the installation of up to 10,000 residential and small commercial Home Area Network devices to provide customers with options to conveniently control or manage their energy use based on lifestyle or operating choice; and the implementation of advanced energy management control systems with automatic demand response (Auto-DR) capability at customer facilities. In combination with time-based rates, these service options provide customers with greatly enhanced tools to manage overall energy, reduce peak electricity demand, or shift their consumption from on- to off- peak periods.

Direct load control devices include programmable communicating thermostats and other devices that support load reduction or load shifting for air conditioners and other appliances and equipment during peak demand periods. Participating customers receive financial incentives in return for SMUD gaining the ability to turn off, or turn down, major appliances during times of system need. SMUD is installing the software platform for a demand response management system to provide more effective and centralized administration of direct load control operations and to enable a more robust two-way communication and feedback loop with its customers.

Grid Automation & Management

SMUD's Smart Sacramento Project involves a partial deployment of advanced distribution grid assets that equip SMUD's distribution circuits with automated control and operation capabilities. These systems enable more effective management by SMUD to improve reliability and efficiency of grid operations and better optimize the use of assets. The project includes installation of DA equipment and systems for 102 (90 are 12kV and 21 kV circuits, and 12 are 69kV circuits) out of 635 circuits:

- Distribution Automation (SCADA) at 36 substations
- Installation of 15 automated field devices (69kV)
- Installation of 366 automated field devices (12kV/21kV)
- Installation of primary monitoring devices required to implement Volt/VAr control or CVR (12kV/21kV)
- Addition of two way communication to 180 existing switchable capacitor banks
- Communication system from automated devices to Distribution Management System (DMS)
- Demonstration of the interoperability between DMS, OMS, and AMI that results in improved efficiency in the distribution system and automatic restoration of service after an outage.

Distribution automation systems will include advanced automated equipment to improve the performance of distribution systems. SMUD is deploying automated switches, automated capacitor banks, remote fault indicators, and feeder monitors integrated with its energy management system on 102 distribution circuits. This equipment automatically responds to power disturbances and provides voltage regulation and isolates interrupted circuits. SMUD expects to reduce service interruptions and the frequency and duration of outages and the need for truck visits to maintain the distribution grid. Distribution automation assists the grid integration of solar and wind power installed on or near residences and commercial buildings. The DA project will include the following investments:

- **SCADA Expansion:** 100 of the 136 substations have SCADA capability. The SCADA system collects and reports voltage levels, current demand, MVA, VAR flow, equipment state, operational state, and event logging. Distribution System Operators are able to remotely control capacitor banks, breakers and voltage regulation. SMUD will extend this capability to the remaining 36 substations.
- **Install Automated Circuit Switches on 69kV Circuits:** SMUD will install 15 automated circuit switches at strategically located at normal open points and at the mid-point of the 69kV sub-transmission circuits. These switches will be monitored via SCADA and allow for remote sectionalizing after a fault condition as well as reduced time spent on fault location.
- **Install Automated Circuit Switches and Reclosers on 12kV and 21kV Circuits:** SMUD will replace manually operated switches with remotely controlled 12kV and 21kV switches and reclosers (366 automated field devices) strategically located on the targeted circuits. These locations will also provide overall power monitoring data (circuit amps, voltage levels, real and reactive power flow, and so forth). These automated switches will greatly improve system reliability by allowing system operators the ability to

remotely switch the distribution system to isolate fault conditions quickly while minimizing the number of customers affected by an event.

- **Install remote controls for capacitor banks:** SMUD will install remote controls for 180 existing switchable capacitor banks. Currently, the control strategies for these capacitor banks consist of time, VAR, or EMS control. The current control strategies will be replaced with controllers that respond to a Distribution Management System (DMS) control strategy. This remote functionality will enable system engineers and operators to better control and optimize the real-time VAR flow and voltage supported by field capacitor banks.

Distribution system energy efficiency improvement will be achieved through integrated voltage control from capacitor controllers and energy management system. The capacitors improve voltage, volt ampere reactive control, and power quality and increase distribution capacity by reducing energy losses on the distribution system.

Distributed Energy Resources & Distributed Generation

SMUD's Smart Sacramento Project includes a field test of plug-in electric vehicle charging stations to assess their technical performance, vehicle charging patterns, and effects on electric distribution system operations. The project includes installation of following equipment and systems:

- **Up to 220 Electric Vehicle Charging Stations:** PEV charging stations are being deployed at up to 40 parking spaces on college campuses and 180 residences across the SMUD service territory. The charging stations also include meters and monitoring equipment to evaluate performance and charging patterns and their impacts on the distribution system. The equipment will be operated and further tested under direct load control and dynamic rates using the Demand Response Management System.

Apart from the ARRA funded Smart Grid Project, SMUD is undertaking an energy pilot program that includes installation of two Premium Power 500kW/6 hours zinc bromine flow batteries systems, one A123 500kW/500kWh lithium ion battery system with 500kW Solstice advanced inverter technology, fifteen 8.8 kWh residential systems and three -30 kWh community storage systems.

APPENDIX C: Smart Grid Technologies

This appendix addresses Smart Grid technologies in the following categories.

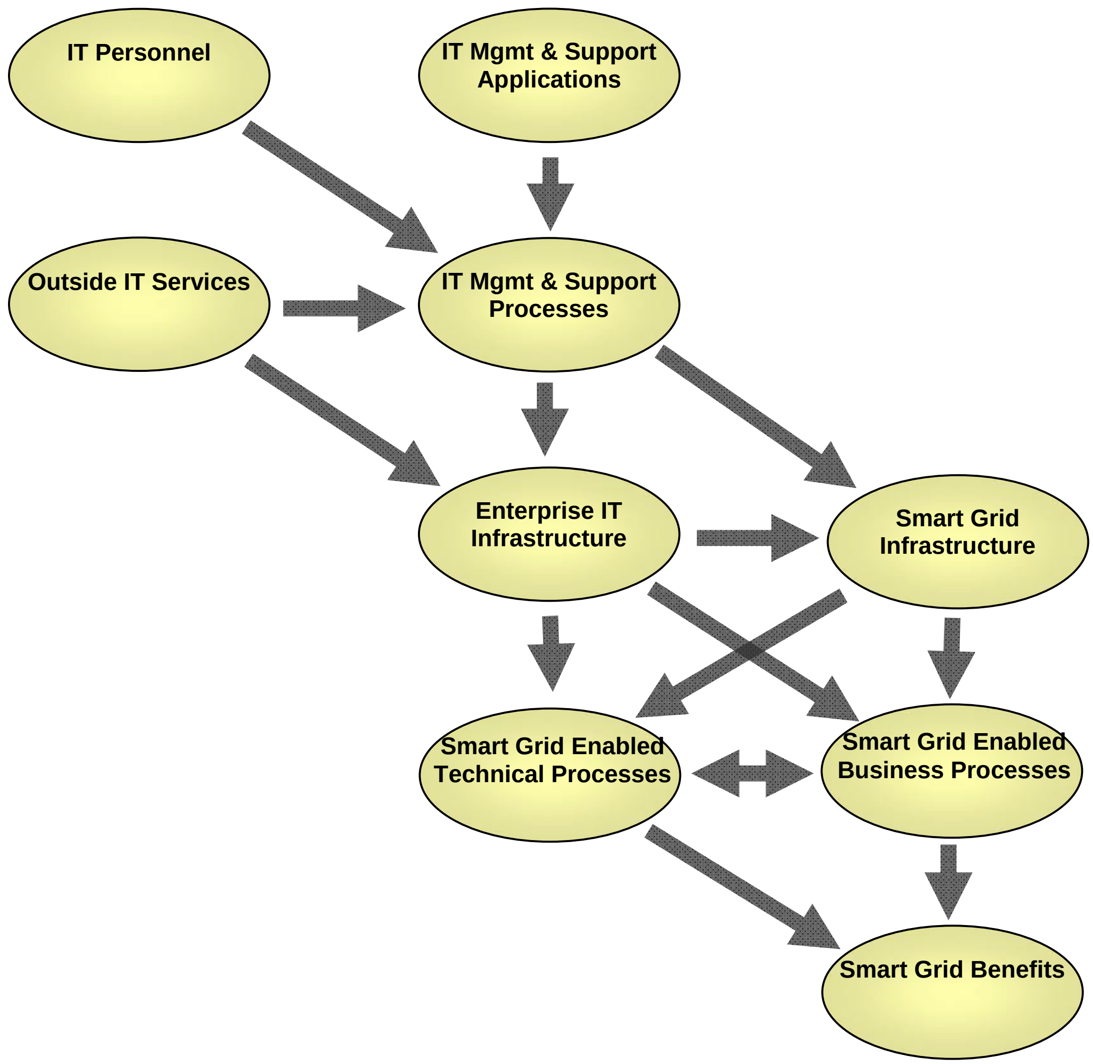
- Information Technology and Back Office
- Advanced Metering Infrastructure (AMI)
- Meter Data Management
- Transmission and Substation
- Distribution
- Customer Enabling / Demand Response Technologies
- Distributed Energy Resources /Distributed Generation Integration
- Electric Vehicles
- Communication Infrastructure
- Workforce Efficiency

Information Technology and Back Office

Full Smart Grid integration and fulfillment at any utility requires interweaving the utility's information technology (IT) systems—back office hardware, platform software, application software, data, and IT processes—that enable and/or employ the utility's planned Smart Grid capabilities with all the real electrical and electronic resources deployed in the field, and with the application programs and business processes that operate those resources. The figure below illustrates the interrelationships that must be established and some of the interdependencies.

Building these interactions is not a sequential activity. Each is created incrementally, concurrently with others, and each utility will start in a different place(s), depending on its existing resources and staff capabilities. The paragraphs that follow discuss some of the priorities and issues involved.

Figure C-1: IT Interrelationships



This means that each POU's transition to Smart Grid enablement must encompass the broad range of activities summarized in the table below. Of course, the distinct circumstances affecting each POU will strongly influence the POU's approach to planning and executing each activity, and no utility will attack all of this at one time. The key is to identify the most productive starting points and proceed in a sustained and coordinated manner.

Table C-1: Information Technology Domain Objectives and Tasks

<table>
<tr><th>Domain</th><th>Objective</th><th>Tasks</th><th>Sub-Domains</th></tr>
<tr><td>IT Infrastructure</td><td>Provide an IT infrastructure that fully enables the POU's planned Smart Grid capabilities.</td><td>Add, upgrade, or replace IT infrastructure hardware, software, and data.</td><td>Backbone Network
Data Center Facilities
Server Resources
Data Storage Resources
Internet Services
Disaster Recovery</td></tr>
<tr><td>IT Management and Support Processes</td><td>Employ IT management and support processes that fully enable the POU's planned Smart Grid capabilities.</td><td>Add, upgrade, or replace IT management and support processes.</td><td rowspan="2">Security Assurance
Network Management
Data Center Management
Server Management
Data Storage Management
Asset Management
Program / Project Management
IT Development
IT Testing
Disaster Recovery Planning and Testing
IT Change Management
IT Trouble Management
IT Help Desk
User Training
IT Technical Training</td></tr>
<tr><td>IT Management and Support Applications</td><td>Employ applications that fully enable required IT management and support processes.</td><td>Add, upgrade, or replace IT management and support applications.</td></tr>
<tr><td>Outside IT Services</td><td>When advantageous, employ IT infrastructure and services provided by 3rd parties.</td><td>Add, upgrade, or replace IT infrastructure, processes and/or applications.</td><td>All of the above.</td></tr>
<tr><td>IT Personnel</td><td>Employ IT personnel fully capable of managing and operating IT infrastructure and processes required for smart grid.</td><td>Train existing personnel, add new personnel, and/or hire contractors.</td><td>System Analysts
DBAs (database administrators)
Network Administrators(s)
Security Administrators(s)
IT Operators
Asset Manager(s)
Program Manager(s)
Help Desk Team
Business Continuity Team</td></tr>
<tr><td>Business and Technical Processes</td><td>Employ business/technical policies and practices that fully utilize planned Smart Grid capabilities to achieve planned Smart Grid benefits.</td><td>Add, upgrade, or replace business/technical policies and practices.</td><td>Business Analytics
Engineering Analytics
Rate Design
Customer Service
Customer Accounting
Supply Management
System Operations</td></tr>
</table>

Domain	Objective	Tasks	Sub-Domains
IT Users	Employ utility personnel fully capable of managing and performing business/technical policies and practices that fully achieve planned Smart Grid benefits.	Train existing personnel, add new personnel, and/or hire contractors.	Distribution Operations Revenue Metering Asset Management Document Management Program Management Business Continuity

POU: Publicly Owned Utilities

Advanced Metering Infrastructure (AMI)

Two technologies constitute advanced metering infrastructure (AMI): metering and communication. Metering is a utility core competency, and utilities generally find that available automated meters are highly capable relative to their requirements. Further, most AMI communication technologies are available with meters from more than one meter manufacturer, so that metering requirements can be met with almost any communication method. Therefore, the AMI choice usually is driven by the AMI characteristics and the utility's needs in communication.

That communication issue focuses on communication *to meters* because they are numerous, and their cost is a significant driver of overall system cost. Other communication methods, used to ferry data to/from other points in the network, are less consequential in the choice of AMI technology. Fundamentally there are two core options for communicating with revenue meters: wireless and wired. Alternative technologies and their suppliers are tabulated below and described in the following sections.

Table C-2: AMI Supplier Mapping to Communication Technologies

Category	Meter Communication Technology	Suppliers
Wireless	RF Mesh	Elster, Itron, Landis+Gyr, Silver Spring Networks, Tantalus Systems, Trilliant Networks
	Hub-and-Spoke (RF Tower)	Sensus, SmartSynch, Aclara
	Public cellular	SmartSynch
Wired (Power Line Carrier - PLC)	Power Frequency	Aclara
	High Frequency Carrier	Cooper / Cannon, Echelon
	Low Frequency Carrier	Landis+Gyr

RF: Radio Frequency

Optical fiber does not appear in the above table because optical fiber modems are more costly than modems for radio and power line signals. Though a few utilities have deployed a few meters using optical fiber, this approach has not gained a significant market presence due to its unfavorable economics compared to the alternatives discussed below.

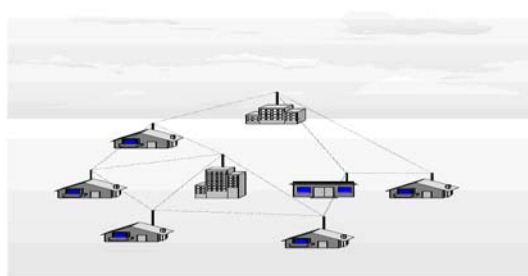
Wireless AMI Technologies

For wireless, AMI vendors have chosen either radio frequency (RF) mesh or hub-and-spoke architectures. These networks are private, that is, they are owned and operated by the utility. Another wireless alternative is to use public cellular networks, and this is also described below.

RF Mesh

The RF mesh architectures provide a smart and dynamic relaying option where a meter's data may be routed through any of several physical paths as it traverses back to the data collection point (access point) for the system.

Figure C-2: RF Mesh Network Architecture



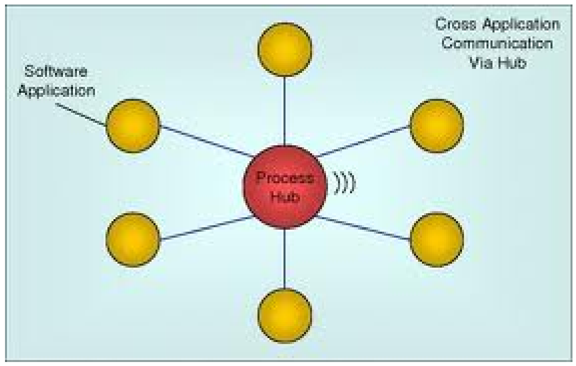
Two-way communication is enabled by unlicensed, low-power RF chips in AMI electric meters and AMI modules on gas and water meters at customers' premises. A network of gateway RF collectors mounted on utility poles or in meters is used to channel unlicensed, low power RF communications from hundreds of meters in their vicinity to the utility's head end AMI system. Backhaul data communications from these collectors can be provided by a variety of technologies including cellular, general packet radio service (GPRS) and broadband.

The availability of routing options is determined by the actual deployment, but the intent is that every meter will have multiple communication options. The goal with this architecture is to ensure 100 percent connectivity between the meters and the data collection points. The mesh architecture optimizes the probability of achieving that result. Some of the advantages of RF mesh networks are the minimal infrastructure and associated capital cost, acceptable latency, fairly large bandwidth and most use a 900 MHz frequency band. As with all technologies, the mesh architecture does have certain negative characteristics. The first being that, due to the dynamic nature of the physical paths that the data will traverse, there is an inherent uncertainty associated with system latency and data throughput. Most AMI applications are not negatively impacted by that non-deterministic characteristic of the mesh. When that does pose a problem on a particular link or path, some systems can be modified to force a specific route so that the performance of that link (or links) becomes stable. Some disadvantages include terrain and distance challenges for rural areas, proprietary communications and limited Smart Grid expansion capabilities to integrate with distribution automation devices.

Hub-and-Spoke

The hub-and-spoke (RF Tower) architecture provides only one path between the central hub and each individual end point meter.

Figure C-3: Hub-and-Spoke (RF Tower) Architecture



RF Tower solutions utilize two-way communications enabled by licensed medium power RF chips in AMI electric meters and AMI modules on gas and water meters at customer premises. A RF tower gateway (base station) (RF TGB) located in the utility's service area is used to channel communications from thousands of meters in their vicinity to the utility's head-end AMI system. Multiple RF towers are used and redundant coverage between towers and end-point devices is designed into the system. Backhaul data communications from these RF TGB stations is typically broadband.

This design has the advantage of providing a dedicated link and therefore has the potential to deliver relatively short and defined latency characteristics as compared to mesh. The data throughput may be higher as well but that is determined by how much bandwidth is available in the cell (the picture shows one cell). Since each device in the cell must share the available bandwidth for that cell, a crowded cell may not deliver high throughput. Vendors offering this solution offer the option of simply adding more hubs so that, over time, the system can be broken into smaller cells therefore increasing the available bandwidth to each device in the cell. This architecture only provide one path to the hub so there is a higher probability that that more endpoints will not have a connection to the network. In that case each situation is solved independently by adding repeaters (which now impacts latency) or other solutions like installing special antennas, and so forth. Other disadvantages of this solution include licensing for those frequencies, uneven terrain can provide challenges in rural areas, proprietary communications, and a large infrastructure capital investment is usually required.

Licensed and Unlicensed Frequencies

AMI vendors have chosen both licensed and unlicensed frequencies for their individual solutions. Both choices have been successful, but there are pros and cons to each. For the unlicensed frequencies, "spread spectrum" technology is used because it is specifically designed to operate in a potentially congested radio environment. The Federal Communications Commission (FCC) has also provided incentives for the use of spread spectrum by authorizing higher power and wider bandwidth when that technology is utilized in the unlicensed bands. Unlicensed does not mean unregulated, but those frequencies don't come with all of the protections afforded to licensed frequency users. A more detailed discussion of this is presented in the Communication Infrastructure section below.

Broadband Wireless –WiMAX is a broadband wireless technology that is now being deployed an overall Smart Grid telecommunications option. WiMAX is also being used as the AMI portion of the Smart Grid solution providing a single network for both AMI and Smart Grid functionality. WiMAX employs a hub-and-spoke physical architecture and is based on the Institute of Electrical & Electronics Engineers (IEEE) 802.16 standard.

The principal proponent of WiMAX for meter automation was General Electric, which recently discontinued its WiMAX offering. WiMAX remains a viable choice for other wide area Smart Grid communication.

Broadband Wireless – LTE

"Long term evolution," called LTE and also "4G," is the name given to the next generation of cellular telephony. Early in its definition, it was seen as principally serving handheld mobile devices such as cell phones. At that time, WiMAX was widely regarded as the logical choice for high-capacity communication with fixed field assets. But LTE's perceived applications expanded as communication technology continued to advance and, by the time WiMAX technology was actually ready for deployment, it was clear that LTE could capably serve Smart Grid purposes. LTE has higher capacity and greater quality of service control than WiMAX, and appears at this time to be overtaking the early WiMAX successes.

Utilities have been hesitant to employ public cellular networks for large-scale meter and distribution communication due to concerns about quality and reliability of service, as well as cost. LTE includes technical features that make it possible to manage both of these aspects more rigorously than all third generation (3G) cellular technologies. Increasingly, utilities are choosing LTE for some wide-area Smart Grid support.

Cellular Data Networks

Existing (3G) cellular data networks are also being used as optional AMI infrastructure. The advantage is that the network is already deployed and maintained by the cellular operators. A primary disadvantage is that the utility must pay a recurring access fee that sometimes is out of synch with the cost structure of the AMI business case. It has been reported that some off-tariff rates have been negotiated that will make using this infrastructure financially feasible for utilities. The applicability of these networks is also influenced by their geographical area of coverage and how that relates to the utility service area.

Wired AMI Technologies

The wired AMI systems use either the existing power line infrastructure or an existing broadband network as their communications medium.

Powerline Communications

The powerline communications technology category for AMI includes probably the oldest that is still being deployed today. These systems operate by either injecting a carrier frequency onto the power lines that is significantly higher than the 60 Hz power that is already using the wires, or the injection of a low frequency that is relatively close to the actual power grid frequency. The other option is the phase modulation of the 60 Hz power.

All these systems have the advantage of being able to use an infrastructure that is already in place and which, by definition, has physical connectivity to all customers. They also have inherent disadvantages. For high frequency power line carrier (PLC) systems, the biggest issue that must be solved is that the power grid was design for 60 Hz and not the higher frequency being used by those systems. For some systems, this technical fact can require modification of the distribution network that adds cost and complexity. The signal of the highest frequency systems is limited in how far it can travel on the distribution lines. The low frequency PLC systems and the 60 Hz modulation technique operate at or close to the natural grid frequency and therefore don't require grid modification.

There are also performance tradeoffs. The high frequency PLC systems do offer significantly higher data transport capacity and lower latency than the low frequency PLC systems and 60 Hz modulation systems.

PLC communication to the meter is enabled by installing equipment at each distribution substation to modulate the 60 hertz voltage wave shape to provide outbound communications over the power line to the electric meter. This same equipment is also used to detect distinctly unique inbound electric current pulses from each electric meter. Also, electric meters can be equipped with short-range RF chips to communicate with AMI modules installed on nearby gas and water meters. Backhaul data communications between substation equipment and the utility's head-end AMI system can be provided using a variety of technologies including telephone, radio and broadband. PLC has limited bandwidth relative to RF systems and presently does not support IP addressability. Also, a mixed hybrid PLC and RF communication solution is required to communicate with gas and water meters. Some advantages of PLC are that it uses existing infrastructure such as poles and wires, it is more cost effective for rural lines, it is effective in challenging terrain and it will work over long distances. Some of the disadvantages are its increased latency and typically lower bandwidth and data transport capacity.

A newer PLC technology that is being deployed is known as broadband over power line (BPL). This technology has the promise of delivering very high capacity, or broadband, performance. It has been proven to be more expensive, but is still being considered as a potential AMI solution, recognizing the possibility that its very high data transport capacity may enable high-value applications that are not yet recognized.

Telephone

Sometimes referred to as plain old telephone service, or POTS, wired telephone has been a mainstay of utility communication for decades. But its use is limited to selected high-value applications, such as substations and large customers. It has not become a staple of residential meter communication for a number of reasons. High on the list are:

- Differing regulatory jurisdictions between electric and telephone utilities create a patchwork of agreements related to on-site service work, and it is difficult for both utilities to be sure that the phone line will not be disconnected from the meter in error by telephone service workers. Worse, electricians and others do not recognize the connection and often remove it.
- The cost of a dedicated line—that is, subscribed and paid by the utility—to the meter is too high for residential applications. Therefore, residential meter communication employs the customer's line, and the meter quickly disconnects if the customer lifts the handset to make a call while the meter is sending data to the utility. But the customer may fail to pay the phone bill, and is free to discontinue telephone service, leaving the utility without access to essential meter data.
- Increasingly, it is commonplace for customers to have only wireless phones.

Therefore POTS remains a useful tool for utilities, but not for AMI meter communication *to meters*. Utilities also need communication to meter data concentrators, and telephone is cost-effective in that application. This is discussed in the Communication section, below.

Meter Data Management

Meter data management concept has transformed over the last decades. Before the introduction of Smart Grid and advanced metering infrastructures (AMI), what was referred as meter data management was mainly for meter asset management which was all about the meter as a device and for meter reading storage for billing purposes. From the meter asset management perspective, the key metrics being tracked dealt with more device types, quantities, and performance, maintenance, inspection and testing related functions, and it did not matter where the device was located at any particular point in time nor the usage or the activity of the device was. For this purpose, utilities either relied on custom built databases or third-party meter asset management/testing systems. From the billing perspective, what mattered was typically the readings manually collected from the meters that were read once a month or even less frequently for some customer types (such as agricultural, rural or seasonal customers) for billing purposes. This function was fulfilled mainly within the customer information systems (CIS) to complete the meter-to-cash process.

With the introduction of Smart Grid and the increasing deployment of AMI systems that can provide up-to-the minute interval data from service points, meter data management systems (MDMS) have evolved within the last 10 years. Today, the MDMS is all about usage at the service point among other things (for example, service quality). The key metrics that needs to be tracked include knowing what meter is installed at what service point at any point in time, and also the usage and activity on that meter, regardless of the type meter installed.

With mainly the introduction of advanced meter reading (AMR) systems, meter reading process became more automated and more efficient reducing the meter-to-cash cycles. This also led to the increase of the frequency of the meter reading data that could be collected from the service points (especially for large commercial and industrial customers). With the increased reading intervals, storage for meter reading is addressed by automated meter reading databases/applications such as Itron's MV90 platform. Today, many utilities still use this platform for automated meter reading purposes.

However, the increasing deployment of AMI systems that can provide up-to-the minute interval data from service points created the need for a more flexible, scalable and capable platforms that could consolidate more data regardless of its underlying metering technology, and process and translate more data to meet the needs of other systems and stakeholders both within and outside the boundaries of the utility.

Initially what started as a meter consumption data storage and management solution that typically import data that are delivered by smart metering systems, then validate, cleanse and process those before making it available for typically billing purposes, has evolved into more of a middleware platform that is able to integrate to existing enterprise applications, translate the vast quantities of raw meter data into systems and help to streamline utility business processes. MDMS used as a metering data aggregation platform can reduce integration complexity between multiple metering and enterprise systems. MDMS can interface with, including but not limited to, outage management systems, workforce management systems, asset management systems and engineering systems. MDMS may provide reporting capabilities for load and demand forecasting, management reports, customer service metrics, and other operations and support the activities.

The underlying key MDMS functionalities today can be summarized as follows:

- Consolidate AMI data from multiple sources and vendor platforms in a timely manner;
- Process AMI data as required including;
    - Performing Validation, Estimation and Editing (VEE) to cleanse the database,
    - creating billing determinants, not only for traditional rate structures but also for evolving time-based and dynamic rates.
- Store data for all in a way that supports smaller utilities, those just focused on C&I customers, and also the needs of larger utilities with millions of customers and hourly or sub-hourly data;
- Distribute the data to the appropriate systems, not just to the CIS but also to outage management, demand response, engineering analysis tools/applications, distribution management systems to name a few. To do this effectively, the core meter data

- Manage events relating to AMI data and equipment, serving as the intermediary between other systems; such as OMS and the AMI systems to take full advantage of event notifications and alarms initiated by AMI end-points on a real-time basis;
- Publish the data for use by downstream systems, internal and stakeholders including customers, and make it available for ad hoc reporting;
- Offer a set of integrated business applications that address key operational processes which benefit most from the availability and granularity of AMI data, such as revenue protection, load research, load forecasting, settlement, complex billing, and distribution asset planning, management and optimization;
- Address the customer side needs of AMI as well by not just simply presenting load profiles to customers who will not be able to readily utilize such information but by including the appropriate systems and tools that will enable customers to understand their options and the impact of these options on their consumption and/or bills, and to take actions.

Today, MDMS is more seen as the backbone of AMI; that without it, some argue that fixed AMI metering systems are no more useful than mobile AMR systems[53]. And that, MDMS makes possible most of the ancillary business benefits offered through frequent data acquisition such as outage management, network planning and operations, customer service applications, demand-side planning, and so forth[54]. Furthermore, as Gartner stated in its recent research for meter data management products; "Renewed interest in energy commodity management, which is spurred by energy security concerns and an interest in demand-response programs, is driving the need for multipurpose metering data repositories that can meet requirements outside of their traditional use in a meter-to-cash (revenue management) process"[55]. Network/asset analysis requires consumption data to improve asset utilization and reliability while the increased focus on customer empowerment requires on-demand access to metering and event data for demand response and operations. And, with the increasing integration of renewable distributed generation, distributed energy resources and plug-in electric vehicles (PEVs), MDMS can also store metering data related to these assets, including load profiles, supply data characteristics and make this information available to other external systems for improved grid operations.

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[53] Hall, Mark D.,"Why Meter Data Management is The Key to Unlocking AMI Usability"

[54] Ibid Hall, Mark D.

[55] "Magic Quadrant for Meter Data Management Products", Gartner Industry Research Note G00225576, Sumic, Zarko, 20 December 2011, Gartner, Inc.

Transmission and Substation

Transmission

The leading automation and Smart Grid technology in transmission applications is the phasor measurement unit (PMU), a device that records dynamic voltage and current simultaneously with other PMUs and provides the measurements to a processor that uses them to assess transmission conditions. Because the measurements are very precisely synchronized in time, these units are sometimes called synchrophasors. The PMUs use Global Positioning System (GPS) satellite signals to set their internal clocks to the same reference, enabling the measurement synchronization. Applications of these measurements include:

- Validating transmission network models
- Determining network stability margins
- Based on the above margins, maximizing transmission line load while maintaining stability
- Detecting islanding
- Recording network anomalies and disturbances

If PMUs had been in routine use in the U.S. transmission network in August of 2003, it is widely believed that operators could have detected the instabilities that developed in the network following the first precipitating event—a transmission line sagging in the heat grounded itself against a tree—and prevented the large-scale cascading blackout of the northeastern U.S. The instabilities expanded and amplified for several hours after the first event before causing the more rapid sequence of failures that blacked out the region. Accurate measurements would have detected the anomalous dynamics and allowed operators to separate transmission line segments to isolate the problem to its source area.

That blackout was a key motivating event in the movement toward smart "grid" which, at first, meant the transmission grid. Only later was the moniker expanded to apply to distribution as well.

Starting within the last two years, PMUs and the associated data processing are available from more than one supplier. Though experience with them is quite limited at this time, projects funded partly by American Recovery and Reinvestment Act of 2009 (ARRA) funds are rapidly expanding the industry's experience, and PMUs will soon be an anchor element of transmission network management systems.

Substations

Substation technology has advanced at a steady pace for the last three decades. In the early years, supervisory control and data acquisition (SCADA) became a standard method of first monitoring, and more recently controlling, resources in substations. SCADA systems included sensors on key substation points and a communication box that sent the sensor values back to a SCADA Master Station at the utility distribution operations center.

The next step from there was to add processing to the communication box, allowing some data evaluation and decision making in the substation. A new category of harsh-environment "Intelligent electronic devices" (IEDs) for substation management became available, and these became coordination points for gathering and handling substation sensor data before communicating them to the utility.

After data networking became common in offices in the early 1990s, suppliers applied ruggedized networking equipment to substations. Substation networks are now common at larger or more critical substations. With a network in place, each sensor can become "smart" with the addition of an IED. It was a short leap to smart sensors that include processing and a network interface. A modern substation now includes many smart sensors networked together, along with remotely operable switches and voltage regulators, all communicating with the operators and automation systems at the utility.

The technologies for all this automation are quite mature. But substation automation on this scale is not common. Many small utilities are only now deploying basic SCADA, and have very little of it at their smallest substations. Application of substation automation is still rapidly evolving. A technical standard called International Electrotechnical Commission (IEC) 61850[56] for substation network communication has gained wide acceptance since about 2005, and now many devices are available that support it.

Automation functions implemented by substation automation include:

- Volt/VAR management
- Feeder voltage optimization
- Transformer monitoring
- Transformer load management
- Switch / breaker monitoring and control, and more as discussed in the following section.

Most recently has emerged the concept of a distribution management system (DMS) that integrates the previously-separate functions listed above. A DMS may be composed of software that runs at the distribution operations center and uses all the substation automation resources to optimize energy delivery.

[56] http://www.iec.ch/smartgrid/standards/

Distribution

Smart Grid technologies applicable to distribution can be identified as:

- Distribution Automation Devices / Technologies
    - Remote Sensing Technologies
    - Automatic Reclosers
    - Remotely Operable Distribution Switches
    - Faulted Circuit Indicators
    - Voltage Regulators
- Distribution Management Systems/Applications
    - Supervisory Control and Data Acquisition
    - Distribution Management Systems
    - Automated Fault Location, Isolation and Service Restoration (FLISR)
    - "Self-Healing" Networks
    - Real-Time Load Flow Applications and Analysis
    - Capacitor Switching
    - Voltage Optimization
    - Distributed Resource Optimization

Each of these is discussed in the following paragraphs to describe how they operate and how they are expected to evolve to constitute a Smart Grid element.

Distribution Automation Devices / Technologies

Remote Sensing Technologies

A sensor is a device that senses a physical quantity and produces a measurable output. Today, sensors are widely used on the electrical grid to measure electrical and non-electrical parameters (see Figure C-4). The electrical parameters reflect key aspects of the distribution grid and their values provide insight into whether the grid is operating reliably and efficiently. These parameters may be used in a variety of applications. For example, voltage, harmonics and reactive power measurements can help utility personnel to operate their system more efficiently. Voltage and current can be used to avoid thermal and voltage violations in real-time. Partial discharge, leakage current and transient data are good indicators of potential equipment failures. Transient data may also help identify an exact fault location or confirm whether protection systems worked properly. Non-operational sensor data may be used to determine the exact condition of power system equipment. These data parameters may be analyzed in a condition based maintenance assessment to detect conditions that can lead to faults.

Figure C-4: Key Parameters Measured by Sensors

Electrical Parameters	Non-Electrical Parameters
• Voltage	• Temperature
• Current	• Moisture
• Active and reactive power	• Pressure
• Energy	• Vibration
• Harmonics	• Acoustic/ultrasonic
• Transients	• Dielectric properties
• Partial discharge	• Gases in headspace
• Leakage current	• Dissolved gases in oil
	• Photo-optical effect
	• Mechanical stress and strain
	• Displacement
	• Motion/speed

Source: [SCADA and Remote Sensor Technologies, SAIC, December 2010]

Today's sensor products have a rich set of features such as on-board storage, SCADA interfacing capabilities, broad support of communication protocols (DNP 3.0, modbus, and so forth), multiple communication options (Wi-Fi, WiMax, Radio, and so forth), higher sampling rates to capture wave form data, and easier field installation. With these advanced capabilities, sensor technologies are poised to provide much more data on the health and status of the grid than ever before.

However, collecting lots of sensor data and making good use of that data are two separate issues. Pike Research estimates that due to accelerated deployments of meters and sensors, the market for Smart Grid data analytics will grow more than ten-fold in the next five years, from $356M in 2010 to roughly $4.2B in 2015[57]. The emerging analytic capabilities and intelligent applications that can process sensor data and provide actionable information are crucial parts of remote sensor systems. Some of the advanced applications available today or on the horizon include fault location, fault prediction, automatic reconfiguration, advanced Volt-VAR control, conservation voltage reduction, conditioned based maintenance, advanced system assessment and planning, distribution state estimation and others.

As sensor technology has advanced, it has become more viable for voltage and current monitoring on medium- and low-voltage networks. Advances in materials such as semiconductors, fiber optics, and optoelectronics are driving this advancement.

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57 http://www.pikeresearch.com/newsroom/smart-grid-data-analytics-market-to-reach-4-2-billion-by-2015

Today, many utilities operate their systems based on limited or estimated system data, which may result in wrong decisions and inefficient operations. Added to this, increased infrastructure costs, higher reliability demands, load growth and a decline in the number of qualified field personnel are all factors are driving utilities to operate better. Remote sensors can be part of a solution to help utilities overcome some of these challenges.

Sensor data and derived intelligence can help in real-time operations by improving system reliability, improving customer service, decreasing system losses, improving line-crew dispatch, increasing overall system efficiency and reduce operations and maintenance (O&M) costs. Logged data and historic power system information can support various assessments and studies including load growth studies, system planning and streamlined calculation of reliability indices.

Automatic Reclosers

Automatic reclosers are switches that open when a fault current occurs, and close again after a defined period (say, three seconds) to attempt to clear the fault or to restore service if the fault has self-cleared. Examples of faults that may clear this way include a snowy branch touching the line, and a squirrel that bridges the line to a nearby ground. In these cases, customers experience a power blink, but service is not interrupted for more than a few moments. Most California publicly owned utilities (POUs)—indeed, most utilities nationwide—have automatic reclosers in service.

As communication and processing have become less expensive, newer reclosers have become available with data acquisition and communication functions that record and communicate fault information. In a full Smart Grid context, these devices will provide vital information, and will respond to remote commands from the utility and/or other smart devices to maintain service when temporary faults occur.

Remotely Operable Distribution Switches

Every utility has distribution switches, and most of them are manually operated. The above reclosers are one example. Most reclosers, though they open and close automatically, remain open if the fault does not clear and must be closed manually to restore service, after the fault has been manually diagnosed and remedied. A remotely operable recloser can be closed by utility operators once the fault has been remedied or isolated, perhaps by switching other automatic or remotely operable switches.

Another example is a sectionalizing switch. This is a switch that normally is kept open, but can be closed to connect two feeders that are near each other. Such a switch typically connects the two feeders somewhere mid-way along their length. When a fault occurs on one feeder, switches on that feeder (including the auto-recloser mentioned above) can open the line before and after the fault, and the sectionalizing switch can then apply power from the adjacent feeder to restore service to the rest of the faulted feeder. This is done manually by most utilities now. But communication and control technology already is available that enables utilities to perform these functions remotely. When integrated with other Smart Grid technologies, the remote operable switches will be the devices that actually restore power in "self-healing" distribution systems.

Faulted Circuit Indicators (FCIs)

These are simple coffee-mug sized devices that hang on distribution lines and mechanically change state when a fault current surges through them. The mechanical motion exposes some indicator that the fault occurred. For example, the FCI may be white, and a disk on it may rotate to expose a bright orange section after a fault current occurs. When a feeder breaker has opened at the substation, utility field crews drive along the feeder looking for the first FCI that has not tripped. When they find it, they know they've just passed the fault location.

As with reclosers, FCIs are now available with communication capability, eliminating the need to drive the feeder to find the fault location. Currently, this capability informs distribution operators and service crews. Full Smart Grid implementation will feed this information into automated logic that will use it to operate the remotely operable distribution switches described above to quickly effect service restoration.

Voltage Regulators

Electric utilities traditionally maintain distribution system voltage within the required range using substation transformers with moveable "taps" (Load Tap Changer or LTC) that permit voltage adjustments under load. In addition, voltage regulators located in substations and out on distribution lines are commonly used for voltage control purposes. Some transformers are equipped with a voltage regulating controller that determines whether to raise or lower the transformer tap settings or leave the tap setting unchanged based on "local" voltage and load measurements.

The basic strategy for distribution feeder operation is to maintain acceptable voltage conditions for all customers while being as efficient as possible. Typically, this means keeping the voltage in the lower portion of the acceptable range, which usually is specified by American National Standard Institute (ANSI) standards. The voltage profile along the distribution feeder, and the flow of reactive power (VARs) on the feeder, are typically maintained by a combination of voltage regulators and switched capacitor banks installed at various locations on the feeder and in its associated substation. Each voltage regulator includes a controller that raises or lowers the voltage regulator tap position in response to local (at the device) current and voltage measurements. Similarly, each capacitor bank may include a controller that switches the bank on or off in response to its local measurements.

Distribution Management Systems/Applications

Supervisory Control and Data Acquisition (SCADA)

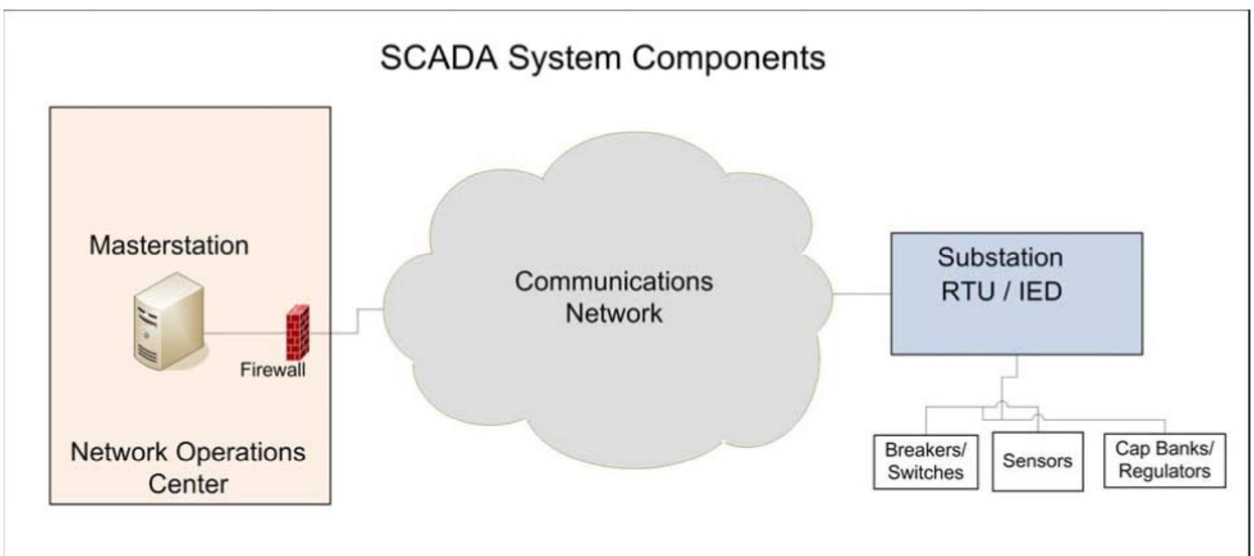
SCADA systems of today typically monitor and control power system equipment down to the substations. There are very few SCADA installations beyond the substation fence. However, more and more utilities are looking closely at implementing SCADA beyond the substation as communication costs decrease and capabilities increase. High-speed, high-bandwidth, robust, and secure communication systems are now enabling the integration of remote sensors and distribution equipment into SCADA systems.

SCADA systems are composed of four main components (see Figure C-5 - Main SCADA Components):

1. **Master station software** - This software is usually located at the utility's operations or control center. It has a Human Machine Interface (HMI) that enables operators to monitor system parameters and issue control commands.
2. **Communications system** - The two-way communication technology that is used to transfer data between the master station and system components. This system may be a hybrid solution of multiple communication technologies.
3. **Automation hardware** - Includes Remote Terminal Units (RTU), Intelligent Electronic Devices (IED), or Programmable Logic Controllers (PLCs).
4. **Remotely controllable power system equipment or sensors -** Power system devices like reclosers, breakers, switches, regulators, capacitor banks and various types of sensors.

SCADA vendors typically provide master station software and automation hardware in their product offerings that can accommodate multiple communication options.

Figure C-5: Main SCADA Components



The value of SCADA stems not only from its capability to monitor and control system devices over vast distances, but also for its historical data logging, event recording and reporting. This information is not used in real-time but is very useful for trending load growth and load flow analysis, load prediction, maintenance and planning purposes. Logged analog SCADA data can be used for energy loss calculations and to support management decisions on whether to invest in or upgrade systems and equipment including the installation of line capacitor banks to minimize VAR flow, re-conductoring of overhead lines and increasing system voltage.

Operation outage counters may be graphed and examined for an increasing trend in operations or for an excessive amount of operations. The most troubled circuits may then be inspected by line workers and appropriate actions taken to prevent permanent outages, such as trimming trees and reducing the number of temporary outages. This actual system information enables more accurate studies and ultimately better financial decisions.

Many substation RTUs or gateways have integrated Transmission Control Protocol/Internet Protocol (TCP/IP) serial server functionality, which allows for remote downloading of engineering data and remote engineering access without ever having to leave the office. Digital fault data may be downloaded after an event has occurred. This information is typically downloaded locally using a laptop computer and the IED vendor's software. It may be downloaded remotely if communication systems enable remote engineering level access. If the actual fault is located by line workers the digital fault data may be examined to ensure the relay or recloser control operated as intended and for the correct type of fault. If a mis-operation was believed to have occurred, the digital fault data may be used as forensic evidence to discover the root cause of the mis-operation and rectify the incorrect settings.

If a utility has microprocessor-based relays in operation, the advantages of having a typical SCADA system integrated with these relays and other IEDs are likely to outweigh the financial investment in many situations. Most of today's microprocessor-based relays and recloser controls offer fault locating technologies which have proven to be very reliable. If a feeder has several taps down-line of a recloser control, fault locating technology can be misleading due to the numerous potential fault paths. This situation can be aided with the use of faulted circuit indicators (FCIs) with integrated communications. When used in combination with relay and recloser fault locating technology, even more information can be fed into the SCADA system allowing for more accurate fault location and crew dispatch. In many cases, crews can be sent to within 3-4 pole spans of the fault.

When SCADA is fully integrated with an Outage Management System (OMS) utilizing Advanced Meter Infrastructure (AMI)/Automatic Meter Reading (AMR)/Customer Information System (CIS) data, a fault location can almost immediately be identified allowing for immediate response from dispatch. This also allows for repair crews to be dispatched with more accuracy saving costly driving and repair time. Any combination of the previously mentioned SCADA systems can greatly improve system reliability.

Distribution Management Systems

The idea of a distribution management system (DMS) is relatively new. DMS has evolved from the monitoring and control of SCADA system technologies that now are over 30 years mature to become a collection of systems for the planning, analysis, and operation of distribution system networks. Common DMS functionality includes:

- Remote monitoring and control of distribution equipment (switches, reclosers, regulators, capacitor banks, dynamic VAR compensators, and faulted circuit indicators)

- Asset health monitoring (transformers in particular, but also circuit breakers and protection and control systems)
- Network modeling and analysis (typically power flow, voltage, and faulted circuit analysis)
- Outage management (including automatic outage notification, fault locating, restoration, and verification)

The most advanced DMS technologies include:

- Dispatch and control of distributed resources (especially solar, emergency back-up generators, onsite customer generation, and in some cases micro wind and battery storage)
- Voltage optimization (optimizing service entrance voltage to improve system efficiency)
- Real time/dynamic equipment rating (especially circuits, substation getaways, and transformers)
- Failure prediction (especially in substation and distribution transformers)
- Fault analysis (especially the identification of momentary outages and high-impedance faults)

The 'leading edge' of DMS research and development includes:

- System optimization (especially voltage optimization and DER)
- Active load management (including PCTs, but more interestingly the concept of actively managing customer loads to increase load factor)
- Self-healing network operations
- State estimation

The idea of DMS is linking current distribution system operating data to high-capability analysis software that can produce optimal distribution operating decisions. An integrated set of analytical resources (the DMS) receives near-real time or real time inputs from utility sensing systems, analyzes current operations, makes operating decisions and/or recommendations, and issues commands to execute them. The inputs can come from any of many systems: SCADA, AMI, outage management system, work management system, and so forth The commands are issued to distribution devices, such as breakers, switches and reclosers, switched capacitor banks, voltage regulators, and load tap changers (LTCs). In concept, DMS applications are utilized in routine distribution operations, and in outage management. DMS also extends to the efficient management of planned work.

DMSs are currently offered by several suppliers. Relative to the above-described concept, each has strengths and weaknesses. Each supplier's DMS is strong in that supplier's traditional strong domains. For example, the DMS from a supplier well known for an excellent outage management system will have strong outage management decision making support. A different vendor, perhaps with long experience in electric system analytical modeling, will have a DMS that is stronger there.

DMSs are in an early evolutionary stage. The capability and value of DMSs will increase as customer generation, energy storage, and demand response programs increase the complexity of the decision processes in operating electric distribution systems.

Automated Fault Location, Isolation and Service Restoration (FLISR)

Reducing the time and labor associated with locating and isolating outages in the distribution system is the lowest of the low hanging fruit for improved reliability and reduced operating costs. The ability to quickly locate and isolate faults requires sensing and measuring voltages and currents beyond the distribution feeder circuit breaker. The most advanced utilities are deploying communication faulted circuit indicators that can sense the magnitude and direction of fault currents and report them to a SCADA or DMS system, and in some cases to switching devices located in the distribution system. These technologies focus on actions after a fault has occurred but there are emerging technologies that can predict faults before they occur.

Advanced signal processing technology is being used to analyze distribution system voltages and currents in a way that can actually predict an imminent failure. Current research focuses on distribution and substation transformers, circuit breakers, and voltage regulators. With this technology, as insulation begins to break-down the resulting leakage currents and coronas can be detected and analyzed to help predict where and when a failure may occur. While not ready for commercial deployment, this technology is likely to first be deployed to monitor key system assets and important distribution circuits.

Again relying on advanced signal processing, the computational analysis of faults in the distribution system is becoming more apparent. This technology has been widely used in high-voltage transmission systems to pinpoint faults on long transmission lines, evaluate the performance of protection and control systems during faults, and enable the use of advanced protection schemes including single-pole switching. As capabilities and improved and costs have dropped, digital fault recording is becoming more prevalent in sub-transmission and distribution substations and will eventually be deployed on every distribution feeder.

"Self-Healing" Networks

The idea of self-healing electric distribution networks is appealing, but will not be fully realized for many years. What is practical now is to install the switches discussed above, with voltage sensing and communications, and develop logic and control software that coordinates operation of some switches with others to isolate faulted feeder segments from un-faulted ones, and restore power to the un-faulted segments. This is commonly referred to as feeder reconfiguration.

Feeder reconfiguration applications improve reliability by reconfiguring distribution feeders in response to power system faults and overloads. To perform these functions, these systems use data from both SCADA systems and remote sensors to find and isolate faulted zones and determine restoration plans. To implement this function, the distribution topology must have at least two adjacent feeders separated by a normally-open switch. Feeder reconfiguration can be implemented as a simple system with a single automated switch installed at a normally-open tie switch location, or a more advanced system with multiple automated switches enabling multiple potential distribution configurations. Current system topology, geography, customer needs, and utility legacy systems may impact the optimal choice. Most SCADA vendors that offer master station software are trying to transform their solutions into a Distribution Management System (DMS) which includes a suite of applications to manage every aspect of the power distribution system. In such cases, feeder reconfiguration can be considered as one application within the DMS offering.

Real-Time Load Flow Applications and Analysis

Real-Time Load Flow (RTLF) applications uses a system connectivity model and real-time data from the DMS to simulate what is actually happening on the distribution system at the moment. In the RTLF application, AMI data can be used to provide information on real-time loading, interval demand and voltage levels from end delivery points on the system. RTLF provides an overview of the power flowing on the system, the current state of all connected devices and switches, and is a useful tool for operators to visualize what is happening. This overview can help operators make better decisions, as well as see the impacts of the decisions they have already made. System losses can be observed, and attempts to minimize them can be made. Optimization and balancing the way power is flowing can save the utility money. Some vendors offer a planning and analysis mode component as part of the RTLF module of DMS.

Capacitor Switching

Capacitors in substations and on distribution feeders help maintain unity power factor and minimize reactive losses. For this reason, utilities have installed capacitors for decades in locations where customers operate reactive loads. Such loads are particularly typical of industrial facilities, but also exist in many other locations.

It is common for utilities to control capacitors with timers that switch the capacitors into or out of the distribution circuit according to when customers' reactive loads typically are operating. This works well, but is suboptimal because load operation and behavior is rarely as regular as a timer. Current technologies for measuring power factor and controlling distribution equipment make it possible to dynamically switch feeder capacitors based on actual power factor. A simple VAR threshold is set and capacitors are switched in or out when a feeder exceeds the threshold. The system is kept very close to unity power factor, helping to reduce system losses.

The value of capacitor control can be extended by implementing volt / VAR control (VVC), mentioned earlier in the section on substation automation technology. VVC is a real-time application that determines the set points for capacitor banks, load tap changers (LTC), and voltage regulators to concurrently optimize distribution system voltage and minimize VAR flows through distribution lines. Voltage control and VAR control can be operated together or independently, but optimal benefits are achieved when operated in an integrated fashion. VVC solutions generally incorporate a centralized optimization algorithm whose objective is to either reduce peak load or minimize system losses. Real-time current and voltage measurements are typically acquired through the SCADA system. More detailed voltage data from AMI can be a valuable addition. In an advanced VVC application, voltage regulators and capacitor banks can be controlled separately for each phase, in which case efficiency and power quality benefits will increase. Distributed generation with on-board automatic voltage regulators that can remotely change the terminal voltage are also potential resources for VVC applications.

Voltage Optimization

VVC solutions generally incorporate a centralized voltage optimization algorithm referred as "Conservation Voltage Reduction (CVR)" that reduces energy delivered slightly, reduces distribution losses significantly, and can reduce peak load. Line voltages are reduced while still meeting minimum required levels set by industry guidelines (such as ANSI C84.1). The concept is not new, but improvements in monitoring and control technologies now make it easier and more effective to implement. Published EPRI reports estimate that on-average there is a 0.7 percent total energy savings for each 1 percent drop in voltage.[58] POUs can use this as one way to reduce peak demand and associated demand charges while, at the same time, optimizing delivery efficiency for customers.

Successful implementation depends on near-real-time voltage and power factor data supplied by remote sensors. SCADA can be used for data collection and to enable automatic or manual control of voltage regulators, capacitor banks, and load tap changers. AMI provides highly detailed voltage data that optimizes the control decision process and verifies control accuracy. The moderate latency of AMI communication is acceptable.

Control logic is implemented either or both at the utility or in substation IEDs (intelligent electronic devices) programmed to control voltage on feeders.

The example of a Tennessee electric cooperative serving 22,000 accounts illustrates how this benefits utilities[59]. The cooperative implemented voltage optimization during peak hours to shave demand. Prior to a SCADA deployment, the utility was unable to dynamically measure feeder voltages or calculate system losses. After installing SCADA, the utility found that its system supply voltage was increasing during evening hours, in-turn causing end-of-the-line voltage to rise above 130 volts. Combined with other factors, such as unbalanced circuits and excessive VAR flows, this resulted in system losses in the 7 percent range.

The utility continues to optimize voltage during peak times but now, with measurements and control provided by SCADA, is able to reduce end-of-the-line voltages to 120 volts. SCADA data identify unbalanced circuits and allow the utility to redistribute loads to balance the system. They also implemented automatic capacitor switching (discussed below) for each feeder to reduce VAR flows, re-conductored some highway right-of-way lines and increased primary

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58 http://tdworld.com/overhead_distribution/epri - green - circuits - project/

59 "SCADA and Remote Sensor Technologies Report", R.W. Beck, Inc., December 2010

voltage to 25 kV on some distribution circuits. These combined actions reduced system losses to approximately 3.8 percent, for roughly a 5 million kilowatt-hour savings per year.

The amount of energy saved by using volt/var optimization and CVR has been shown to be significant, and this can best be accomplished using a DMS system. Using the state estimator and real time load flow applications, the DMS system will determine the voltage profile for each circuit, and switch capacitor banks and/or feeder sections to optimize the circuits.

Once the voltage profile is optimized, the DMS system can tell the substation regulators to reduce the feeder voltage to save energy. This is difficult to accomplish without a DMS system, as the end-of-line voltage can dip below ANSI limits. Tuning the system by hand is effective, but as the voltage profile changes with time of day, savings are no longer maximized. Conservative settings are required in that case, to avoid low voltage in certain areas. All of this would instead be handled dynamically and automatically by the DMS system, allowing utility to save energy at the maximum rate, with minimal intervention by operators.

Distributed Resource Optimization

Distributed resources provide electricity at the site of the application and therefore reduce the load served by a centralized power generating facility and the electricity losses that occur during delivery of power from the centralized generating facility to that load. If less electricity is required to be transmitted to a specific location, then there will be a reduction in the line losses associated with that reduction in power flow. This value can be optimized by allowing distributed resources to serve nearby load during periods when generation costs and losses are greatest.

Value for the distribution system can also be derived when sufficient distributed resources are deployed on a specific feeder or substation and can be dispatched to reduce peak demand on that feeder or substation. Such deployment can potentially defer distribution upgrade investments, but these installations must be located to reduce specific overloaded conditions.

Technological barriers—such as the efficiency of energy storage mechanisms that will improve reliability and generation during peak loads—currently limit the value of intermittent distributed resources, such as wind and solar. However, emerging storage technologies are expected to have improved performance and/or lower cost. Coupled with smart-grid enabled remote control, distributed resources and associated storage devices could be dispatched to reduce peak load, improve voltage, and minimize losses during periods of high generation cost.

Many utilities already have agreements with large customers that have backup generation—such as data centers and hospitals—to allow the utility to dispatch the customers' generation at times of need. The amount of such generation is commonly a significant contribution to meeting the utility's requirement. Smart Grid will automate the process and expand the available capacity by allowing utilities to employ a much larger number of smaller capacity generators owned/operated by customers.

In addition, distributed resources will improve customer reliability if industry standards allow "islanding," so that the distributed resources could provide power during a local or system outage. Existing standards do not allow this practice because attaching generation to the power grid without utility knowledge or control poses major safety hazards to utility personnel. This practice will also require sophisticated metering and control systems to match the load with the distributed resources at any given instant. AMI and Smart Grid technology will provide the communication links to address these concerns and lead to changes in these restrictions.

As the need for more efficient and reliable electric systems increased, other specialized systems have evolved alongside SCADA technologies. These systems for distribution utilities include outage management systems (OMS), distribution management systems (DMS), new customer information systems (CIS), and geospatial information systems (GIS). Many vendors offer the entire suite of OMS, DMS, and SCADA products as a package, which seamlessly integrate and provide a single distribution model for all three applications.

The ability to use OMS and SCADA data with DMS information provides a capability to pinpoint a faulted line segment and apply advanced feeder reconfiguration algorithms to restore power to as many un-faulted segments as possible. This type of fully integrated OMS/DMS/SCADA system, paired with high speed IP communications allows power to be restored to the maximum number of customers in a matter of seconds, instead of minutes or even hours.

Other uses for an integrated OMS/DMS/SCADA include Volt-VAR control from the SCADA master station computer. A SCADA system with the ability to obtain "end of the line" voltage can dynamically control voltage regulators and switched capacitor banks to maintain proper system voltage and stability. This significantly reduces losses and improves distribution efficiency.

Customer Enabling / Demand Response Technologies

Recent reports predict that 100 million smart meters will be deployed in the next five years, and that half of these will have a built-in home area network (HAN) gateway for in-home energy management programs and services. One publisher's survey of 77 US utilities found that 21 percent plan to integrate a HAN gateway into every smart meter deployed[60]. While the potential for HAN technology to benefit utilities and consumers is clear and real, it is not clear how soon that potential can be realized.

The HAN may give utilities a powerful platform to establish two-way communications with devices in consumer premises. Consumers that value detailed information about their energy costs will be interested in tools that enable them to modify their energy consumption and reduce their environmental footprint. Companies ranging in size from industry leaders to startups are actively seeking a broader consumer energy management market, amid high uncertainty about whether such a market will materialize.

[60] ON World's survey of 77 utilities in the U.S.

Utility directions in addressing communication to home devices vary widely. Some utilities focus on implementing demand response programs through thermostats and load control devices. Others are pursuing consumer energy awareness through in-home displays (IHDs) and dynamic pricing programs. HANs range from simple in-home energy displays showing colors only, to more comprehensive IHDs showing usage, cost, and time. In-home devices they may communicate with include programmable thermostats, pool pumps, water heaters, electric vehicles (EVs), and small scale distributed generation and storage.

Studies have found that including advanced demand response (DR) applications such as dynamic pricing in the Smart Grid business case can increase the energy reduction benefits by over 30 percent. Providing consumers with real-time energy information enables them to manage their energy expenditures as well as feed micro generated energy sources such as solar and wind back to the grid.

Smart Appliances

The Energy Independence and Security Act of 2007[61] requires the integration of Smart Appliances and consumer devices that can interact with the Smart Grid and provide consumers with timely information and options for controlling energy use.

Smart Appliances (such as thermostats, heating, lighting and air conditioning systems, washer/dryers, refrigerators) potentially provide an array of benefits to the consumer and the utility, enabling home energy management, reduced utility bills, and energy conservation. Utilities that combine HAN and smart appliances can manage peak demand in ways that go beyond simple DR and load control initiatives. Consumers could utilize a HAN and a home energy management systems (HEMS) with their smart appliances and devices to set profiles, parameters and preferences regarding energy usage and costs, enabling true, automated energy management to shift or shave peak load and save the consumer money.

Smart Appliance refers to a modernization of a home appliance so that it monitors, protects and automatically adjusts its operation to the needs of its owner to optimize energy costs. Smart Appliances, though developing slowly, are expected to provide a number of features that will enable utilities and consumers to reduce and manage energy usage, such as:

1. Dynamic electricity pricing information is delivered to the user, and the appliance, provides the ability to adjust its electrical energy use.
2. It can respond to utility signals, contributing to efforts to improve the peak load management capability of the Smart Grid and save energy by:
   - Reminding the consumer to move usage to a time of the day when electricity prices are lower, or
   - Automatically reducing usage based on the consumer's previously established preferences or manual overrides.

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[61] http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=110_cong_bills&docid=f:h6enr.txt.pdf

3. Integrity of its operation is maintained while automatically adjusting its operation to respond to emergency power situations, helping prevent brownouts or blackouts.
4. The consumer can override all previously programmed selections or instructions from the Smart Grid, while insuring the appliance's safety functions remain active.
5. When connected through a HAN and/or controlled via a HEMS, Smart Appliances allow a total home energy usage approach.
6. It can leverage features to use renewable energy by shifting power usage to an optimal time for renewable energy generation, for example, when the wind is blowing or sun is shining.

HAN Communication

Though millions of in-service smart meters include ZigBee radios to communicate with HANs, very few in-home devices to which they might communicate are in service today. Some utilities and vendors are awaiting more complete standards and communication protocols before full adoption of such technology, as there are over a dozen incompatible protocols available for HANs today.

A big question is: What communication platform is leading the HAN industry today? Four communications technologies have leading potential in the HAN marketplace. Three are wireless standards—ZigBee and Z-Wave (both already used for home automation), and the new 6loWPAN—and the fourth uses the power line: HomePlug Command and Control (HPCC), which communicates data over the building's electrical wiring.

ZigBee is widely seen as the most likely candidate for HAN success. The ZigBee Alliance has been very focused on smart metering. Z-Wave also has support in the home automation market, especially in North America and Europe where it already has significant market share. 6loWPAN is seen as the dark horse, as it is quite new and relatively untried. HPCC offers the advantage of using the same power lines that feed the customer loads, but is restricted to serving wired devices only. Vendors are taking diverse approaches to HAN product development, and utilities are hesitant to move forward with such dynamic changes taking place. As a result, many utilities have implemented trials and pilots, but few have decided to deploy HAN-related technologies on a large scale beyond the meters.

HAN Market

The market for HAN and home energy management systems (HEMS) is at an early stage of development and is characterized by an influx of vendors seeking to capitalize on the perceived opportunity. These vendors range from utility-centric suppliers targeting a key aspect of the Smart Grid (HAN/demand response), to home automation vendors seeking to integrate energy management both into stand-alone systems and into systems oriented towards deployment by broadband service providers. Vendors also include "pure-play" HEMS vendors, home networking equipment providers, and enterprise software vendors. While the HAN market may have tremendous potential, both as part of the overall Smart Grid market and due to increased consumer interest in energy management, it does face a number of challenges, market-oriented and technological, as well as broader economic context.

The uncertainty is illustrated by the following forecast that was included in a mid-2010 report to utilities[62].

> "The HAN device market is forecasted to grow at a compound annual growth rate of 185 percent and to represent a $3.3 billion addressable market by 2012. ABI Research predicts that 17 million home energy management systems will be installed in 2014, as homeowners make a rapid move to control their energy usage."

Since then, the ZigBee Alliance took a year longer than promised to standardize important aspects of the protocol, and both Google and Microsoft withdrew from the home energy management market citing low consumer interest. The US recovery from broad economic recession continues to flounder, and it appears unlikely that home energy-related devices will be a priority for consumers any time soon.

Smart Appliances Market

Significant shifts are taking place in the Smart Grid world, with the potential of enabling millions of consumers to control their energy usage and in-turn, their electricity costs. Utility consumers to date have not experienced "smart devices" such as a smart washer or dryer or refrigerator, the vast majority are still unable to view energy usage or pay their energy bills online. So the questions many utilities are asking are, Will Smart Appliances, connected to the Smart Grid via AMI and HAN networks, achieve significant penetration in our society or is it just another fad that will come and go? Should Smart Appliances be placed on our Smart Grid technology roadmap? And if so, when?

The answers to these questions are complex and vary from utility to utility and region to region. Many factors come into play, with the most important being consumer education, availability at a price point the "durable goods" market will bear, and integration with utility communication systems and programs that take advantage of their "intelligence." It is vital to educate consumers about the benefits of the Smart Grid, and also provide to better understand and engage their energy consumption needs. A recent study found that 74 percent of consumers were unfamiliar with Smart Grid technology. Is this a problem? Yes, introducing Smart Appliances to a marketplace without consumer education only sets the industry and utilities up to fail. Introduction of Smart Appliances into the marketplace will inevitably bring awareness to consumers; however, utilities must also educate consumers and develop the technologies and programs to take advantage of the functionality. Educating consumers about why they are paying a premium for a smart appliance must be addressed to maintain momentum and drive adoption growth in the long term.

A key question for the nascent Smart Appliance industry is the adoption of standards. Currently leading appliance manufacturers are engaged in or planning a limited number of

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[62] ABI Research

"sandbox" or pilot projects with utilities to test consumer adoption and energy management results. These pilots utilize a range of standards, including ZigBee, U-Snap, and even customized hard-wired connections to the appliance. Until more universal standards are agreed upon and supporting utility programs put into place, appliance manufacturers are hesitant to add cost to their products in a highly cost-competitive market without some degree of certainty that the capabilities will be utilized and provide value to the consumer market.

DER/DG Integration

The distributed generation and energy resources (DER/DG) can include programs allowing homes, farms and businesses to generate their own power from renewable sources such as wind, water, solar power, agricultural biomass and utility or customer side storage systems that can send excess electricity back to the grid, and with the mass adoption of plug-in electric vehicles (PEVs) in the future, it can also include the PEVs that can act as distributed generation resources during peak periods. Many renewable resources provide significant electric energy during off-peak times when it is least needed and has a low financial value (such as mid-day, at night, on weekends and holidays). Energy storage can take advantage of this low-value energy and make it available when demand is high, supply is limited, and/or generation costs are at peak. These things occur, for example, during cold mornings when homes, businesses and industries are heating up and during hot afternoons when air conditioning use is maximized. Smart Grid communications and controls can then dispatch the stored renewable supply when it is required and most valuable.

These diverse distributed generation resources typically use inverter-based technologies to convert direct current to alternating current that can be at any required voltage level and frequency. While small amounts of distributed generation will not have a major impact on the distribution grid, widespread concentration of such generation and energy resources, especially with intermittent power flow characteristics (such as wind, photovoltaic, and so forth), can have very diverse impact on the grid; threaten the reliability of the grid and even the safety and well-being of utility customers and personnel. The large concentrations of such resources sending electricity back to grid in an intermittent nature can result in a variety of problems around power quality, including over-voltage, under-voltage, phase voltage imbalance, sudden voltage changes, excessive harmonics, frequency fluctuations and unintended-islanding. While sound electricity network design can reduce or eliminate most of these issues, the utility will still have to maintain the real-time visibility of distributed generation sources on the grid, while also monitoring the distribution network constantly for voltage, power-quality, frequency and other instrumentation.

Thus the specific areas that must be addressed with respect to DER/DG integration include: control and dispatch strategies for DER; strategies to ensure the safety, reliability and protection of the grid; and, the role of power electronic interfaces in connecting DER to the grid.

Today, Smart Grid energy management systems are available that collect and analyze real-time load and weather data to provide hour-ahead load and renewable supply output projections, as well as the cost of other available generation resources, so that utilities can perform economic dispatch and minimize generation costs while meeting demand requirements. However, if available, these systems currently do not take into account the customer owned generation and energy resources. Besides, assessing grid reliability impacts requires more of a systems approach supplemented by enabling technologies and platforms to measure, monitor, manage and control the generation resources, the consumption, the grid operations and assets in an integrated manner. Such approach will require implementation of many of the Smart Grid enabling technologies and systems discussed in this Appendix, including but not limited to: advanced metering infrastructures (AMI); two-way communication infrastructures; distribution and substation automation devices, technologies and systems; and, more.

Another concept often talked about with the increasing integration of DER/DG is the microgrid. Microgrid is an interconnected network of DER/DG and loads that normally operate connected to a centralized grid but can also function separately (in isolation) from the electricity grid[63]. Many public or private initiatives are underway to investigate optimal microgrid design, including the power electronics necessary to connect microgrids effectively to the power grid; conducting field tests of microgrid operation; and assessing the system reliability services that microgrids might provide.

Electric Vehicles

The technology for large scale use of plug-in electric vehicles (PEVs, that is, any vehicle that plugs into conventional electric supply to recharge its batteries) is in its infancy. PEVs are available at a cost premium to gasoline vehicles. The basic technology of their operation appears to be viable, but suffers from limitations, principally a relatively short driving range between charges. In addition, a number of associated technologies that are essential to large scale PEV success are still only in conceptual stages. These include:

- Information transfer between the PEV and the serving utility that provides charging energy to support billing to the vehicle owner (rather than the facility owner), or regulatory change that allows a facility owner to resell energy that is billed to the facility owner.
- Charging apparatus suitable for charging multiple makes and models of PEV, such as may be installed at an "electric gas station" where PEV owners will charge their PEVs at shopping malls and other consumer destinations.

In addition, other central PEV issues remain unresolved, including how long it takes to recharge them, how to pay for electric delivery infrastructure needed to charge them, and how their materials will be recycled at end-of-life.

Advanced metering infrastructures with two-way communication networks will become vital for utility control and load monitoring for PEV applications. Use of PEVs as a dispatchable resource is still a long way to go, but some utilities are looking at using them as a demand

[63] http://en.wikipedia.org/wiki/Distributed_generation#Microgrid

response resource through experimentation of rate structures encouraging customers for off-peak charging and the implementation of vehicle management systems to better and monitor and control PEV loads and storage capabilities.

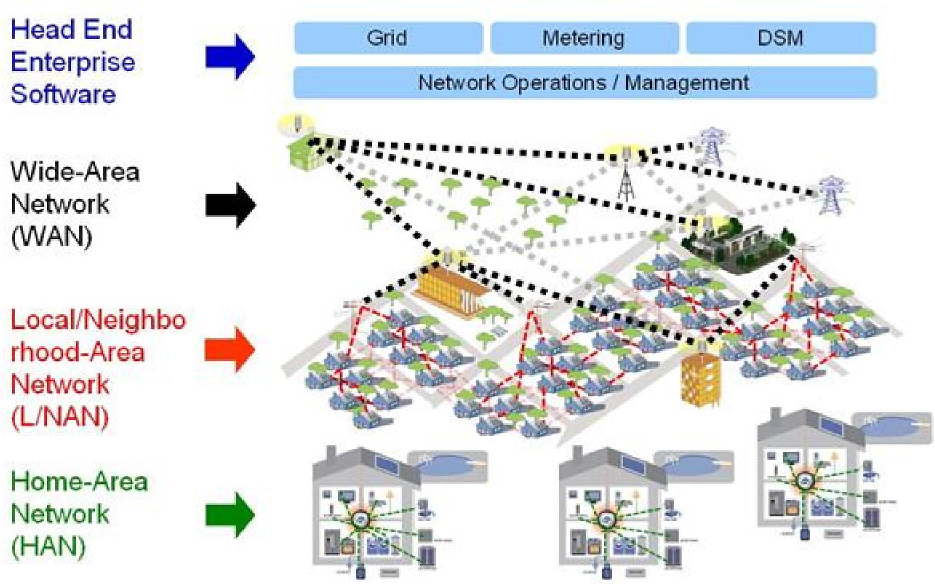
It is reasonable to expect that developments in the next decade will resolve the issues mentioned above and more that will surface as the adoption of PEVs grows in the future , making PEVs practical and attractive on a large scale. Battery technologies already exist that have higher energy capacity and charge up to 40 times faster than available batteries. Standards efforts are under way to define standardized interfaces for the physical charging apparatus and the information transfer. The commercial motives for these developments may be ample to drive their progress.

Communication Infrastructure

Smart Grid Communication Architectures

An overview model of the architecture of the Smart Grid is shown in the figure below. The top layer shows the internal operating resources of the utility. The next three layers show the architecture of the communication between the utility at its field resources, such as meters, distribution devices, and so forth.

Figure C-6: Smart Grid Communication Architecture



The wide area network (WAN) provides the robust, high-capacity, low-latency communication required to fully implement a smart grid. The neighborhood area network (NAN) is often provided by the AMI, while the WAN is often provided by fiber or a broadband wireless technology (WiMAX, for example) or a combination of both. The HANs that are being deployed today are mostly wireless, but power line communication options are also emerging. The ZigBee Alliance and the HomePlug Powerline Alliance are collaborating to provide a multiple-medium solution for HANs where no single medium can provide adequate reliability.

Three types of cellular networks can be considered for the WAN services necessary to support the smart grid. Generally speaking the second, third and fourth generation cellular networks (often called 2G, 3G and 4G networks, respectively) are considered the ones applicable for Smart Grid applications. These xG services employ two competing technologies, GSM and CDMA. These two competing protocols use different methods to encode the data on the radio signal. Each has advantages, but the differences have become unimportant to users, as the network operators build and run the networks to deliver competitive services.

2G is short for second-generation wireless telephone technology. 2G cellular networks were commercially launched on the GSM standard in Finland in 1991.Three primary benefits of 2G networks over their predecessors were that phone conversations were digitally encrypted; 2G systems were significantly more efficient on the spectrum allowing far greater mobile phone penetration levels; and 2G introduced data services for mobile users, starting with SMS or "text" messages.

After 2G was launched, the previous mobile telephone systems were retrospectively dubbed 1G. While radio signals on 1G networks were analog, radio signals on 2G networks are digital. Both systems used digital signaling to connect the radio towers (which listen to the handsets) to the rest of the telephone system. 2G has been superseded by newer technologies variously called 2.5G, 2.75G, 3G, and 4G; however, 2G networks are still used in many parts of the world.

3G, or 3rd generation mobile telecommunications, is a generation of standards for mobile phones and mobile telecommunication services fulfilling the International Mobile Telecommunications-2000 (IMT-2000) specifications by the International Telecommunication Union. Application services include wide-area wireless voice telephone, mobile Internet access, video calls and mobile TV, all in a mobile environment. To meet the IMT-2000 standards, a system is required to provide peak data rates of at least 200 kilobits per second (kbps). Recent 3G releases, often denoted 3.5G and 3.75G, also provide mobile broadband access of several Mbps to smart phones and mobile modems in laptop computers. The latest UMTS 3G release, called HSPA+, delivers peak data rates up to 56 Mbps in the downlink in theory (28 Mbps in existing services) and 22 Mbps in the uplink.

The CDMA2000 system, first offered in 2002, is also used in North America, sharing infrastructure with the IS-95 2G standard. The cell phones are typically CDMA2000 and IS-95 hybrids. The latest release EVDO Rev B offers peak rates of 14.7 Mbps downstream, that is, from the cellular towers to mobile units/cell phones.

The above systems and radio interfaces are based on kindred spread spectrum radio transmission technology. While the GSM EDGE standard, DECT cordless phones, and Mobile WiMAX standards formally also fulfill the IMT-2000 requirements and are approved as 3G standards by ITU, these are typically not branded 3G, and are based on completely different technologies.

A new generation of cellular standards has appeared approximately every tenth year since 1G (analog cellular telephony) systems were introduced in 1981/1982. Each generation is characterized by new frequency bands, higher data rates and non-backward compatible transmission technology.

The first release of the Long Term Evolution (LTE) standard does not completely fulfill the ITU 4G requirements called IMT-Advanced. First release LTE is not backward-compatible with 3G, but is a pre-4G or 3.9G technology, however sometimes branded "4G" by the service providers. Its successor LTE Advanced is a 4G technology. WiMAX is another technology verging on and marketed as 4G.

4G is the short name for fourth-generation wireless, the stage of broadband mobile communications that will supplant the third generation (3G).

Carriers that use orthogonal frequency-division multiplexing (OFDM) instead of time division multiple access (TDMA) or code division multiple access (CDMA), are increasingly marketing their services as being 4G, even when their data speeds are not as fast as the International Telecommunication Union (ITU) specifies for 4G. According to the ITU, a 4G network requires a mobile device to be able to exchange data at 100 Mbps. A 3G network, on the other hand, can offer data speeds as slow as 3.84 Mbps.

From the user's point of view, 4G is more a marketing term than a technical specification. But carriers feel justified in using the 4G label because it lets the consumer know that he can expect significantly faster data transport rates.

Although carriers still differ about whether to build 4G data networks using Long Term Evolution (LTE) or Worldwide Interoperability for Microwave Access (WiMAX), all carriers seem to agree that OFDM is one of the chief indicators that a service can be legitimately marketed as being 4G. OFDM is a type of digital modulation in which a signal is split into several narrowband channels at different frequencies. This is more efficient than TDMA, which divides channels into time slots and has multiple users take turns transmitting bursts, or CDMA, which simultaneously transmits multiple signals on the same channel.

For longer distance communication, wired networks are often more suitable than wireless. The principal medium of wired wide area networks is now optical fiber. Fiber-optic communication transmits information from one place to another by sending pulses of light through an optical fiber. The light constitutes an electromagnetic carrier wave that is modulated to carry information. First developed in the 1970s, fiber-optic communication systems have revolutionized the telecommunications industry and have played a major role in the advent of the Information Age. Because of its advantages over electrical transmission, optical fiber has largely replaced copper wire in core communication networks in the developed world.

The process of communicating using fiber-optics involves the following basic steps.

- Creating the optical signal with an optical transmitter
- Relaying the signal along the fiber
- Boosting or restoring the signal as needed so that it does not become too distorted or weak
- Receiving the optical signal and converting it into an electrical signal.

Fiber optic communications is ideally suited to WAN and backhaul service for AMI, as well as low latency, high throughput data circuits for Smart Grid applications needing that type of performance.

Unlicensed Wireless Systems

The WAN, NAN and HAN may be provided by wireless systems that use both licensed and unlicensed frequencies. There are pros and cons to each choice, described below.

First, it must be understood that unlicensed frequencies are NOT unregulated. All equipment placed in service within these bands must meet specific performance and functional characteristics defined by the FCC (Federal Communications Commission).

The unlicensed frequency bands used by US utilities include the following:

- 902 - 928 MHz (26 MHz bandwidth)
- 2400 - 2483.5 MHz (83.5 MHz bandwidth)
- 5725 - 5850 MHz (125 MHz bandwidth)

This provides a total of almost 225 MHz of bandwidth in the unlicensed bands.

Operation under FCC Part 15, Title 47 Section 15.247 of the Code of Federal Regulations is limited to frequency hopping and direct sequence "spread spectrum," described below. No other transmission techniques are permitted. Section 15.247 defines the technical standards to which these systems must conform. For example, the maximum peak output power of the transmitter shall not exceed 1 watt. If transmitting antennas of directional gain greater than 6 dBi are used, the power shall be reduced by an amount such that the directional gain of the antenna does not exceed 6 dBi. This equates to a maximum transmitter effective isotropic radiated power (EIRP) of +6 dBW (1 watt into a 6 dBi gain antenna).

Part 15 equipment operates on a secondary basis. That is, users must accept interference from other transmitters operating in the same band and may not cause interference to the primary users in the band. Primary users are government systems such as airborne radiolocation systems that emit a high EIRP; and Industrial, Scientific, and Medical (ISM) users. Thus the Part 15 device manufacturer must design a system that will not cause interference with, and be able to tolerate, the noisy primary users of the band. And this is where spread spectrum systems excel because of their low noise transmissions and ability to operate in an adverse environment.

In general, a lower frequency makes it easier it is to establish connectivity to all field devices. For this reason many AMI vendors have chosen the 900 MHz band for their systems. The lower frequencies have less free space attenuation, are not as sensitive to tree density, and can penetrate or wrap around walls and overcome other line-of-sight (LOS) issues, such as rain fade and so forth. These frequencies also don't experience "shadowing" due to buildings, hills, and so forth because of the natural refraction that occurs at these frequencies. This is in contrast to the low frequencies like VHF (150 MHz band). The higher frequencies, for instance 5 GHz, start to experience rain absorption as well as significant multipath. The modulation schemes used today are specifically designed to work at those frequencies and they do provide excellent performance.

Communications systems operating in unlicensed frequency bands use "spread spectrum" methods, a communication technology that was specifically designed to successfully function in a congested environment. Spread Spectrum is a communication technique in which many different signal waveforms are transmitted in a wide frequency band. Radiated power is spread thinly over the band so that conventional narrow-band radios can operate within the wide band without interference. Spread spectrum is used to achieve security and privacy, prevent jamming, and operate with signals buried in noise.

Spread spectrum was developed by the military so that communications could not be jammed in combat situations. This technology was too expensive for commercial applications until the mid 1990s, but it has now become very common technology.

A spread-spectrum transmission offers three main advantages over a fixed-frequency transmission:

1. Spread-spectrum signals are highly resistant to narrowband interference. The process of re-collecting a spread-spectrum signal spreads out the interfering signal, causing it to recede into the background.

2. Spread-spectrum signals are difficult to intercept. A spread signal appears to a narrowband receiver simply as an increase in the background noise. An eavesdropper is able to intercept the transmission only if the spreading details are known.

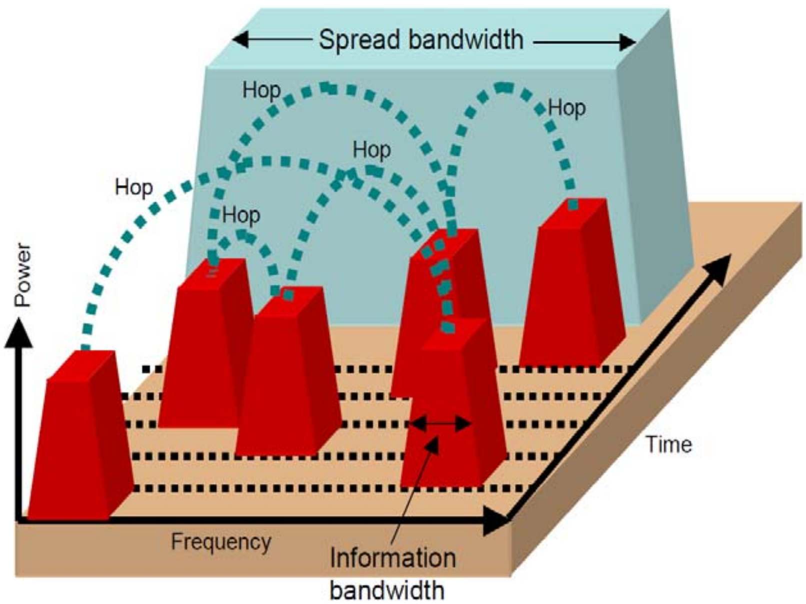
3. Spread-spectrum transmissions can share a frequency band with many types of conventional transmissions with minimal interference. The spread-spectrum signals add minimal noise to the narrow-frequency communications, and vice versa. As a result, bandwidth can be utilized more efficiently.

The two most common types of spread spectrum transmission are frequency hopping spread spectrum (FHSS) and direct sequence spread spectrum (DSSS).

Frequency-hopping spread spectrum (FHSS) is a method of transmitting radio signals by rapidly switching a carrier among many frequency channels, using a pseudorandom sequence known to both transmitter and receiver, but not to others. It is utilized as a multiple access method in the frequency-hopping code division multiple access (FH-CDMA) scheme.

As illustrated in the figure below, a frequency hopping transmission "hops" from channel to channel at regular intervals following a pseudo random sequence. The transmitter and receiver are synchronized to the same hop sequence.

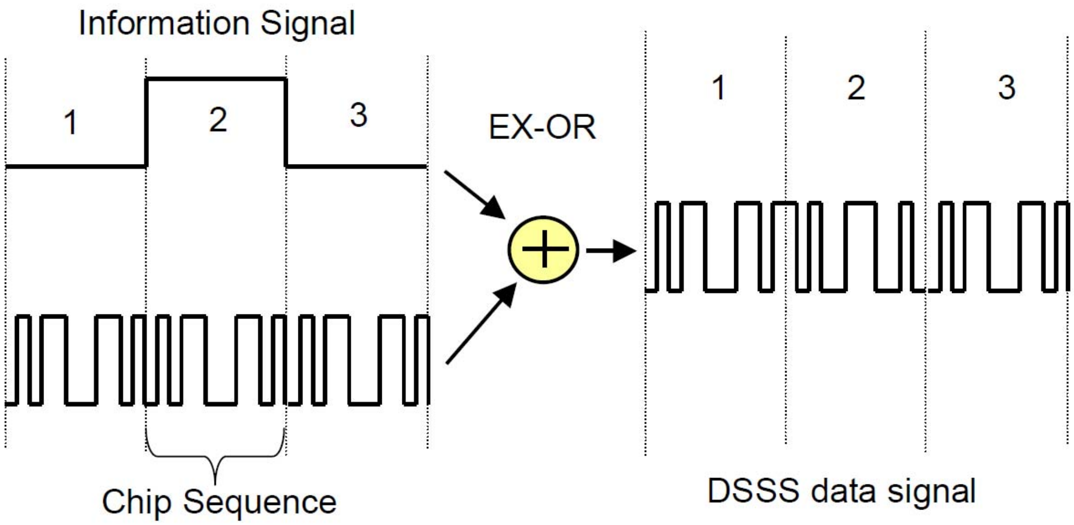
Figure C-7: Communication Frequency Hopping



FHSS can be used to increase the security of the transmission and also overcome jamming and signal fading problems. Common examples of FHSS transmissions are wireless local area network (WLAN) cards for personal computers, GSM mobile phone transmissions, and certain AMI networks.

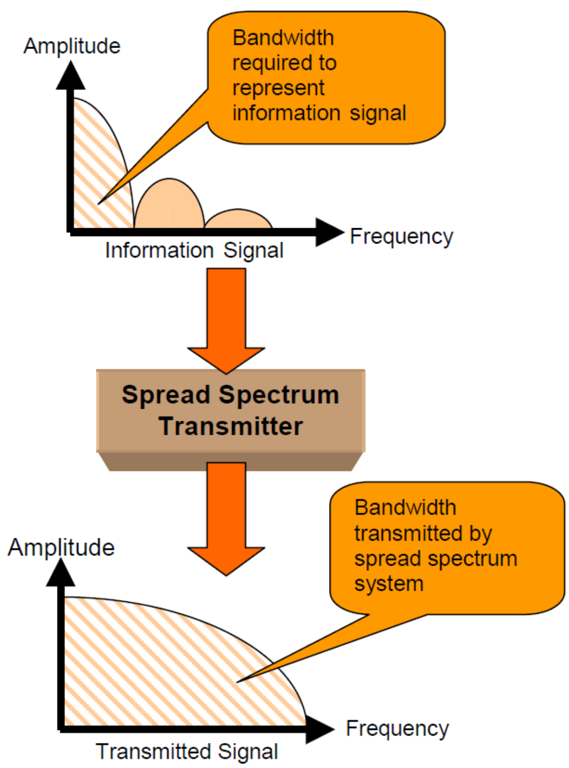
A direct sequence transmission increases the information bandwidth by mixing the information data signal with a much higher rate pseudo random spreading (chip) sequence.

Figure C-8: Transmission Sequence



Both the transmitter and receiver use the same pseudo random sequence to spread and de-spread the information signal.

Figure C-9: Spread Spectrum Transmitter



DSSS also increases the security of the transmission and overcomes jamming, multi-path and signal fading problems. It is also be used as a multiple access technique, such as code division multiple access (CDMA), where each user utilizes a different pseudo random sequence. Common examples of DSSS transmissions are wireless local area network (WLAN) cards for personal computers, IS-95 / 3G mobile phone transmissions (CDMA), and certain AMI systems.

Licensed Systems

Licensed frequency Smart Grid communications systems operate on frequencies that are licensed to specific users for a specific geographical region. The licensing of a particular frequency or frequency band provides the licensee a form of protection against co-channel users by stipulating the proximity of the next user of that exact same frequency. This "frequency coordination" is required to ensure that both systems can operate normally for the FCC to allocate the authorization to use that particular frequency. Obviously that protection provides security from interference that is not afforded the unlicensed frequency users.

For licensed channels, the equipment vendors have technology choices that don't necessarily have the interference rejection capabilities that the unlicensed frequency users must use. This should provide more technology choices and possibly lower cost of system deployment. Of course, the fact that a system is geographically separated from other co-channel users does not guarantee that there will never be any interference. There is always the possibility of communications systems not conforming to their emission limitations or simply not operating correctly. Another risk simply relates to the fact that radio transmission is not exact: distance of communication can vary significantly depending on weather, atmospheric conditions, sun spots, and so forth. Under those conditions, the geographical separation may not be adequate to prevent interfering signals from occurring.

In general, globally, all spectrum is controlled by each country's equivalent of the FCC. In some cases and some countries, portions of the spectrum are set aside for general use such as unlicensed networks. Part of the spectrum in most countries is controlled for military use, public safety, and commercial services. Considering the wide variety of International differences in other areas of public policy, radio spectrum rules are remarkably homogenous.

In each country, portions of the spectrum are set aside for commercial purposes. Some examples of this are broadcast TV spectrum in the 700 MHz range in the US that was recently auctioned for broadband wireless use, or PCS cellular spectrum widely licensed across the US at 1.9 GHz. In virtually all cases only the spectrum licensee can build infrastructure and offer services across its licensed spectrum range. This allows much higher power output without interference across the band, facilitating improved quality of service (QOS). In the US, the most readily usable licensed broadband wireless spectrum is at 2.5 GHz. There is also licensed spectrum at 2.3 GHz and 1.9 GHz that could be used for commercial broadband wireless service delivery.

Among the most sought after spectrum currently available in the US is the 2.5 GHz range. This is very effective for point-to-multipoint signaling to many users. There are two types of 2.5 GHz licenses. The commercial version of the license is broadband radio service (BRS),. These licenses can be owned by commercial companies and bought and sold at will.

The second is educational broadband service (EBS) which can be owned only by educational or religious organizations with a scholastic mission. These licenses can be leased for use by commercial entities. In the US, Sprint/Nextel controls about seventy percent of the BRS/EBS licenses. Clearwire controls approximately another fifteen percent, with the balance held by several smaller block holders. In fact, Clearwire and Sprint concluded a deal shifting some of Clearwire's licenses in metropolitan areas to Sprint in exchange for a larger number of rural or smaller tier city licenses prior to the two companies agreeing to merge their combined 2.5 GHz assets.

Special rules apply for licensed spectrum for certain point-to-point (PTP) links where multiple spectrum holders can co-exist in the same area and use licensed spectrum. This type of PTP link is typically used for robust interference-free backhaul. It features highly focused, high-gain antennas that deliver very tight beam signals. In almost all cases, many users can be accommodated without interference. Spectrum for this purpose exists in the US at 900 MHz, 2.0 GHz, 6 GHz, 11 GHz, 18 GHz, 23 GHz and 39 GHz. Any company that can pass the frequency coordination process (to ensure minimum or no interference) can purchase a PTP license in these bands.

It should be noted that the FCC for various reasons rarely approves PTP licenses in the 900 MHz or 2.0 GHz range. The sweet spot for industry due to cost and capability factors seems to be the 18 GHz range, particularly when used with Ethernet radios versus packet switched technologies.

In licensed bands, utilities today have access to about 30 MHz of spectrum for land mobile communications. This includes 6.95 MHz in the VHF band, 11.85 MHz in the UHF band, 6 MHz in the 800 MHz band and 5 MHz in the 900 MHz band. The 900 – 950 MHz band is used by one of the leading AMI vendors in direct competition with the other AMI vendors that use unlicensed frequencies.

It has been proposed to the FCC that some of the 700 MHz public safety spectrum, and some federal spectrum such as the 1800-1830 MHz band, be made available for utility Smart Grid use.

Workforce Efficiency

Managing field work the “old fashioned” way involved keeping many notes by hand and writing paper “work tickets” to create and track the progress of field work tasks. With computers, many utilities converted the handwritten documents to digital ones. This improved record keeping and accuracy, but did not automate the processes. Genuine workforce management automates the processes of gathering and identifying pertinent data, and produces huge improvements in accuracy and efficiency. Adding “mobile” to the workforce management (by adding data communications) extends its reach to the field staff during the working day, further increasing accuracy and timeliness of both the work and the records.

Workforce management is accomplished with software solutions that give call center operators, field force managers, and dispatch teams computer resources for receiving requests, organizing the utility's responses, tracking the work as it progresses, and analyzing work performance. Mobile workforce management adds data communications, so that field staff can retrieve current information and receive updated instructions and assignments at any time.

Mobile workforce management improves efficiency in many ways. It assists planning for field work by assigning work to suitably skilled staff, assuring they have the needed tools for the work, and optimizing the work sequence to eliminate unnecessary travel time.

With a work management system, call center operators have an organized way to identify customer preferences for appointment times and communication channels (such as email, text message, or phone call). And those preferences are automatically included in the customer account information given to the field work team. As a result, their contact with the customer is more often successful and is more satisfying to the customer. These tools reduce turn-around time from service request to service completion. The automation provides an improved customer experience through faster response times and consistent, effective service.

Functions common to mobile work management systems include:

- Manage the initial service call by capturing data from the CIS, asset management, previous related work events, and other data related to the call
- Provide powerful tools to help the dispatcher create schedules that balance technicians' workload
- Semi-automatically or manually dispatch technicians and crews based on service type
- Optimize route planning for field staff traveling from one site to another
- Communicate with field staff on-line and off-line through any utility or public network to any field crew device, such as a cell phone, laptop computer, and so forth
- Integrate the utility's CIS, billing, provisioning, outage management, and other systems through an integration server using published APIs
- Track daily field crew activity and gather data to analyze long-term trends for strategic planning. Data include windshield time and miles, time-to-complete for all tasks, number of occurrences of each task, etc.
- Manage 100 percent of field resources daily activities, including overtime and conformance to union agreements
- Book appointments in real-time and revise field crew priorities and assignments during the day, as needed to serve existing priorities
- Provide both customers and technicians with a real-time understanding of the status of appointment times

Some of the benefits of mobile workforce solutions can be summarized as follows:

- Increased mobile workforce productivity due to reduction or elimination of idle time, unnecessary travel, redundant data entry, and administrative time
- Reduced costs due to increased ability to handle more work without the proportionate increases in staffing levels through better management of resources
- Streamlined operations due to improved flow of information to and from the mobile workforce
- Improved and enhanced decision-making process due to increased availability of situational data needed to confidently make decisions in the field
- Improved mobile workforce scheduling and dispatch capability due to improved visibility into real-time work, crew, inventory, and equipment status and location information
- Increased responsiveness to unexpected events due to improved communications between the mobile workforce and the corporate office
- Improved employee satisfaction due to increased availability of right tools and resources in the field to get the job done
- Enhanced safety and security due to increased availability of information regarding the whereabouts and condition of the plant and equipment in the work area, as well as real-time location of the mobile workforce
- Reduced regulatory fines and improved compliance due to increased ability to capture information when and where it is performed
- Improved customer service due to increased visibility into customer service requests and restoration efforts

Mobile workforce computing solutions are contributing to the tremendous changes going on in the utility industry within the last 10 years. The promise of better, faster, and cheaper is becoming more pronounced in today's global economy and is forcing even utilities to reconsider the way business is conducted, how it is structured, and how it is handled by utility crews in the field. Technological advancements and declining hardware, software, and wireless service costs are making mobile workforce solutions more reachable to every utility regardless of its size.

Some of the applications of mobile workforce management / computing solutions include, but not limited to:

- **Automated Design and Staking:** Application or suite of applications that allows staking personnel to view/print current power system maps/one-line diagrams of network assets, create/print staking sketches, assign assemblies, materials, develop cost estimate and retrieve any additional information needed to complete a design in the field.

- **Automated Field Force Tracking:** Application or suite of applications that allows utility personnel to view, track, and monitor location/status information of all vehicles/crews in the field in real-time on a spatial format and retrieve any additional information needed to better manage crews/vehicles in the field.
- **Automated Outage Ticketing:** Application or suite of applications that allows field personnel to view and update the status of outage/trouble tickets in real-time in the field. Retrieve/update time critical information from the field in a timely manner such as condition/status of power system network assets, customer information, receive assignments and provide progress on job/outage status to provide dispatch a vehicle to notify customers of power restoration.
- **Automated Service Ticketing:** Application or suite of applications that automates service ticket prioritization, scheduling and assignment to the field crews and allows field crews to retrieve/update the status of service tickets in real-time from the field.
- **Mobile Damage Assessment & Distribution System Inspection:** Application or suite of applications that enables timely collection of damage assessment/asset inspection data from the field and automates management and tracking of damage assessment/ restoration activities and distribution asset field inspection activities.
- **Mobile Maintenance:** Application or suite of applications that automates prioritization, scheduling, management and tracking of major utility assets' maintenance and inspection activities and collection of asset maintenance/inspection data from the field in real-time.
- **Mobile Asset and Inventory Management:** Application or suite of applications that automates collection, management and tracking of utility assets in a spatial format from the field.
- **Automated Meter Services:** Application or suite of applications that automates meter related field services such as readings, installs, accuracy checks, removals and cut-offs and allows field crews to retrieve/ update the status of meter/service related information/tickets in real-time from the field.
- **Automated Right-of-Way (ROW) Maintenance:** Provide a robust and simple field interface for viewing and organizing vegetation management field work. Enable field personnel to view and create geographical vegetation inventory and treatment instructions, collect attributes of sensitive areas and customers. Enable utility to collect vegetation management related data in a central database, share its program data with internal and external stakeholders such as contractors, and analyze crew performance, work progress, and program effectiveness.

APPENDIX D: Use Cases

The seven use cases presented herein illustrate ways in which Smart Grid is widely expected to benefit utilities and energy users in California and elsewhere in 2020. The use cases serve as a reference against which present and future technology capabilities are compared to define the gap between now and the possible capabilities of 2020. The seven use cases presented herein are:

1. Substation Automation - Integrated Protection and Control Improves Service Reliability
2. Advanced Metering – Smart Meters Enhance Utility-Customer Interaction
3. Distributed Energy Resources - Integrated Distributed Generation & Storage Support Grid
4. Demand Response – Active Load Management Reduces Peak Demand
5. Distribution Automation –Integrated Voltage and Feeder Management Improves Power Quality and Delivery Efficiency and Customer Service Reliability
6. Electric Vehicle Charging - Grid Monitoring and Control Enables Wide-scale Electric Vehicle Charging
7. Asset Management - Asset Monitoring Enables Proactive System Planning & Maintenance

Table D-1: Use Case 1 - Substation Automation

<table>
<tr><td>Title:</td><td>Substation Automation - Integrated Protection and Control Improves Service Reliability</td></tr>
<tr><td>Application Description:</td><td>
■ Replace electromechanical relays with digital (microprocessor-based) relays that allow for multiple settings groups and deploy remotely controllable recloser controls and protective elements. Connect all protective devices in a network both at substation and system level.
■ Deploy fiber optic network to the substations to support reliable communication network
■ Conduct engineering studies to determine settings for proper protective coordination under normal distribution network configuration and alternate settings groups for emergency (inclement weather conditions), maintenance or outage-induced reconfigurations.
■ Acquire real-time status information from microprocessor-based relays, reclosers and protective elements down the line through the SCADA system
■ Conduct integrated and protection control using the state estimator and real-time load flow applications to dynamically program the relay settings and control reclosers and other protective elements separately or in coordination to increase system reliability and stability.</td></tr>
</table>

<table>
<tr><td>Primary Business / Operational Need Addressed</td><td>Business Processes Impacted</td></tr>
<tr><td>■ Reduce/avoid line worker hours and mileage to set hot-line tags and disable auto-reclosing
■ Can prevent permanent outages during inclement weather</td><td>■ Outage management process
■ Safety procedures
■ System maintenance
■ Dispatch of distribution / line crews for corrective maintenance should decline as a result of the use of alternate settings groups where possible</td></tr>
<tr><td>Hardware/Software Requirements</td><td>Communication Requirements</td></tr>
<tr><td>■ Automation hardware (Microprocessor-based relay and recloser controls with ability to alter relay settings groups)
■ Engineering analysis tools
■ Master station software (SCADA/DMS) or third party stand-alone application and/or firmware that is embedded in system devices and used for autonomous functionality</td><td>■ Two-way communication from master station to substation and substation to IEDs, microprocessor relays, and line recloser is generally required
■ Moderate latency and relatively low bandwidth systems can be acceptable for basic control of protection settings
■ Communication system reliability should be high and system latency should be less than several minutes for real-time dynamic operations</td></tr>
<tr><td>Technology Challenges</td><td>Business Challenges</td></tr>
<tr><td>■ Alteration of distribution network via switches and line reclosers can cause relay mis-coordination
■ Thorough analysis of network configurations and alternative settings groups is required</td><td>■ Utility may require a physical hot-line tag on substation devices, requiring travel to the device
■ Coordination with neighbor utilities may be required to ensure awareness of alternate settings groups</td></tr>
</table>

Utility Interface Requirements	Training Requirements
■ No direct interface with other utility applications other than SCADA is needed for basic control of protection settings ■ Interface with existing SCADA system if deploying a 3rd party stand-alone application (DMS) ■ Potential value from interface with weather systems that predict inclement weather ■ Interfaces to GIS, OMS or AMI could improve system accuracy and functionality during inclement weather conditions	■ Distribution operators should be trained on the master station software (SCADA/DMS) ■ SCADA technicians need training on programming the relays and re-closer controls, RTUs, and other hardware components

Benefits & Future Potential:	Benefits to integrated protection and control: ■ Reduce outage duration and the number of sustained outages (reliability performance improvement) ■ Improve customer satisfaction and minimize economic losses resulting from electrical disruptions ■ Improve the stability of the distribution network under inclement weather conditions ■ Improve the critical asset life expectancy ■ Reduce capital, maintenance and operating expenditures ■ Improve abnormal situations detection, systems troubleshooting and preventive maintenance from the use of the information stored in the relay ■ Improve engineering analysis and planning using the system currents, voltages and frequency waveforms information stored in a convenient format during power system transient events ■ Decrease the field personnel workload

AMI: Advanced Metering Infrastructure
DMS: Distribution Management System
GIS: Geographical Information Systems
HW/SW: Hardware / Software
IEDs: Intelligent Electronic Devices
OMS: Outage Management System
RTUs: Remote Terminal Units
SCADA: Supervisory Control and Data Acquisition

Table D-2: Use Case 2 - Advanced Metering

Title:	**Advanced Metering -** Smart Meters Enhance Utility-Customer Interaction
Application Description:	■ Advanced metering systems empower customers by providing more visibility to their energy on a near real-time basis ■ Coupled with rate programs such as TOU and CPP, customers can be educated to lower their energy consumption and demand during hours when energy is scarce ■ Two-way, high bandwidth, low-latency AMI networks allow utilities to offer expanded services to customers including remote service switching and pre-pay service ■ Two-way AMI networks can provide real-time outage notification to utilities to help locate and respond to outages more quickly reducing outage restoration times. ■ Utilities can utilize near real-time meter reading data to supplement engineering analysis, system operations, management and planning processes.
Primary Business / Operational Need Addressed	**Business Processes Impacted**
■ Improve utility revenue o Increase metering accuracy o Reduce meter reading costs (scheduled, un-scheduled, connect/disconnect) o Reduce theft o Reduce read to bill float time ■ Improve customer service: o Reduce outage restoration times o Enables platform to provide advanced electricity service options o Provide additional services to customers	■ Customer Service ■ Meter Operations/Reading ■ Rate / Regulatory ■ Revenue/Billing ■ System Operations ■ System Planning
Hardware/Software Requirements	**Communication Requirements**
■ Advanced metering infrastructure including smart meters with service switches and outage/tamper detection capability, IHDs and AMI head end collection engine are deployed ■ Robust CIS/billing systems ■ Optional systems: MDMS, web portal, pre-payment systems	■ Secure, high-bandwidth, low-latency reliable and redundant/resilient communications networks ■ Cellular data networks, hard-wired broadband networks as well as broadband wireless networks (such as community Wi-Fi and WiMAX). ■ Interface to HAN ■ Adequate coverage ■ Scalability
Technology Challenges	**Business Challenges**
■ Managing rapidly evolving standards and technology revisions ■ Managing security and privacy ■ Bandwidth and latency of communications infrastructure ■ Meter data management ■ Integration with GIS, CIS and other systems ■ Integration with metering of other utility	■ Adjust business processes to accommodate automated meter reading/service operations, tamper/outage detection/management and advanced customer service options ■ Developing new tariffs and rate structures ■ Enrolling customers to the new programs and advanced service options ■ Change management

<table>
<tr><td>services
■ Network infrastructure management</td><td colspan="2">■ Business case performance</td></tr>
<tr><td>Utility Interface Requirements</td><td colspan="2">Training Requirements</td></tr>
<tr><td>■ Robust CIS interface is required
■ Interface with MDMS, OMS, SCADA/DMS, DR/DLC systems, EMS/DER Control systems as available</td><td colspan="2">■ Training customers about the advanced electricity service options, rate programs
■ Training meter operations/ field personnel on smart metering infrastructure</td></tr>
<tr><td>Benefits & Future Potential:</td><td colspan="2">■ Increased revenues due to reduced read to bill float time, increased metering accuracy, reduced theft and reduced restoration times
■ Empower customers to reduce energy consumption and demand
■ Improve customer service</td></tr>
</table>

AMI: Advanced Metering Infrastructure
CIS: Customer Information System
CPP: Critical Peak Pricing
DER: Distributed Energy Resources
DMS: Distribution Management System
DR/DLC: Demand Response / Direct Load Control
EMS: Energy Management System
GIS: Geographical Information Systems
HAN: Home Area Network
HW/SW: Hardware / Software
IHDs: In-Home Displays
MDMS: Meter Data Management System
OMS: Outage Management System
SCADA: Supervisory Control and Data Acquisition
TOU: Time-of-Use
WiMAX: Worldwide Interoperability for Microwave Access

Table D-3: Use Case 3 – Distributed Energy Resources

Title:	**Distributed Energy Resources –** Integrated Distributed Generation & Storage Support Grid
Application Description:	■ Diverse energy sources including residential, commercial and small utility scale (such as <5MW) wind and rooftop solar systems and energy storage devices are connected throughout the distribution system ■ Advanced metering infrastructure provides the detailed load information needed to track system load and load changes over short periods ■ Controllable power inverter technologies allows DER to support grid functions such as reactive power support and voltage regulation ■ Advanced protection and operation technologies are utilized to manage bi-directional power flow in distribution circuits ■ Advanced voltage control technologies enable integration of DER resources without adverse impact to the customers ■ Energy storage systems mitigate the adverse impact of intermittent distributed energy resources ■ Energy/Demand Management Systems optimize the dispatch of conventional resources along with DER and DR resources to reliably serve utility customers. ■ Interconnection rules, contracts and tariffs are needed that also enable customers to sell access generation back to the grid when needed.

Primary Business / Operational Need Addressed	**Business Processes Impacted**
■ Increased use of renewable DER resources to obtain environmental and societal benefits. ■ To meet state-level renewable and greenhouse gas reduction regulatory requirements. ■ Use of diverse DER along with advanced integration and control technologies to enhance grid resiliency	■ Supply dispatch ■ Load management ■ Field equipment maintenance ■ Customer billing (for customers that own distributed / renewable supplies or storage
Hardware/Software Requirements	**Communication Requirements**
■ Solar arrays, some large and owned by the utility, and others small and owned by customers ■ Wind generation, similarly large/small and owned by utility/customers ■ Storage resources, such as utility-scale battery systems ■ Instrumentation and control systems (such as Energy Management System, controllable power inverter and advanced protection and operation technologies) for utility monitoring and control of distributed resources	■ Territory-wide communication with utility- and customer-owned generation resources (such as wind, solar), storage resources (such as utility battery systems,), and customer loads, with latency less than one minute ■ Communication with customer meters with latency less than one hour
Technology Challenges	**Business Challenges**
All of these technologies are operable now individually. Technology challenges include: ■ Developing effective control logic to maintain distribution system stability in dynamic	■ This approach has major environmental benefits, but the value of those benefits is not quantitatively recognized in the actual costs of more conventional alternatives.

conditions of variable renewable supply and storage ■ Integrating all of these resources ■ Defining the data models and application-level communication between utilities and customers that will support electric vehicles ■ Achieving industry consensus on needed standards	■ Developing rates that appropriately compensate customers for their roles in this exchange. ■ Regulatory support for the investment needed to create and operate such resources.
Utility Interface Requirements	**Training Requirements**
■ Interface EMS with existing SCADA system / DMS ■ Interface EMS with DRMS if deploying a third-party DRMS system. ■ If installed as a SCADA Master Software plug-in no other utility system interfaces are required to perform the primary VVO and CVR functions ■ Interface with existing SCADA system if deploying a 3rd party VVO and CVR application / DMS ■ Potential value from AMI interface	■ Planning and protection engineers require insight into the operating details of variable renewable supplies ■ Customers need to understand their roles in allowing short-term utility control of loads, interaction with customer- owned energy resources
Benefits & Future Potential:	■ Reduced dependence on fossil fuels for generation, with the consequent reduction in greenhouse gas emission ■ Reduced demand - Avoided T&D and generation costs due to increased capacity of the standing T&D and generation assets, reduced congestion, reduced outages and higher load factors ■ Reduced energy – reduced line losses and avoided generation costs

AMI: Advanced Metering Infrastructure
CVR: Conservation Voltage Regulation
DER: Distributed Energy Resources
DMS: Distribution Management System
DR: Demand Response
DRMS: Demand Response Management System
EMS: Energy Management System
HW/SW: Hardware / Software
MW: Megawatt
SCADA: Supervisory Control and Data Acquisition
T&D: Transmission & Distribution
VVO: Volt / VAR Optimization

Table D-4: Use Case 4 – Demand Response

<table>
<tr><th>Title:</th><td colspan="2">Demand Response – Active Load Management Reduces Peak Demand</td></tr>
<tr><th>Application Description:</th><td colspan="2">■ Enable customers to actively manage their energy consumption in response to information about their energy usage, time-of-use based pricing signals and rate structures that encourage off-peak use
■ Customers are provided with Demand Response(DR)/Direct Load Control (DLC) programs including dynamic rate programs (such as TOU, CPP, RTP) to encourage customers to lower their energy consumption
■ Residential Home Energy Management Systems(HEMs) and devices, residential/ commercial direct load control systems/devices are available for load control within customer premises
■ Customer outreach and education is provided to enroll customers in DR/DLC programs
■ Direct load control programs are provide verifiable demand response with no required customer interaction by allowing the utility to manage their load and the selection of energy sources
■ Demand Response Management Systems (DRMS) utilize near real-time meter reading and system operational data acquired through AMI, SCADA/DMS, DER/EMS, and other sources to optimize the dispatch of DR/DLC resources through DRMS to most efficiently dispatch supply and demand side resources in an economic and reliable manner</td></tr>
<tr><th colspan="2">Primary Business / Operational Need Addressed</th><th>Business Processes Impacted</th></tr>
<tr><td colspan="2">■ Reduce the net cost of energy for customers by reducing the need for additional capacity for generation, transmission or distribution facilities.
■ Improve the overall operating efficiency of the utility by allowing the utility to schedule when to deliver a portion of the customers needed energy
■ Allow the wide-scale integration of intermittent renewable energy sources
■ Ensure reliability of the grid by providing:
o Daily operating reserves
o Ancillary services
o Transmission load relief</td><td>■ Customer Service
■ Rates and Tariffs
■ Revenue/Billing
■ System Planning
■ Energy Trading
■ System Operations</td></tr>
<tr><th colspan="2">Hardware/Software Requirements</th><th>Communication Requirements</th></tr>
<tr><td colspan="2">■ Direct load control devices (such as PCTs, Interactive HVAC Thermal Storage, and so forth.)
■ Smart appliances, residential HEMs/devices
■ Energy demand management system to control demand response alone or in conjunction with other resources
■ Customer web portals
■ Billing and accounting systems cable of working with complex rate structures and billing data</td><td>■ Two-way communications (meter, backhaul and HANs) to end use devices is required for verifiable demand response
■ Cellular data networks (4G), broadband networks (wired internet) as well as broadband wireless networks such as community Wi-Fi and WiMAX can provide pricing, usage and control signals to customers and direct load control devices</td></tr>
</table>

<table>
<tr><th colspan="2">Technology Challenges</th><th>Business Challenges</th></tr>
<tr><td colspan="2">

Measurement and verification of demand response
Service life of DLC devices
Maintenance of in-home devices such as PCTs, IHDs and other devices required to provide information to customers

</td><td>

Realization of financial benefits sufficient to justify system costs
Maintaining positive customer relationships
Developing new tariffs, rate structures, DR/DLC programs
Enrolling customers in the new programs and advanced service options
Maintaining customer participation in voluntary programs
Some of the benefits of load control may become functional at different times during the life of the initial investment making the business case more complex.

</td></tr>
<tr><th colspan="2">Utility Interface Requirements</th><th>Training Requirements</th></tr>
<tr><td colspan="2">

Robust CIS interface is required
Interface DRMS with AMI, CIS
Interface DRMS with SCADA/DMS, EMS/DER Control systems as available

</td><td>

Training customers about the advanced electricity service options, rate programs, DR/DLC programs
Training meter operations/ field personnel on smart metering infrastructure

</td></tr>
<tr><th>Benefits & Future Potential:</th><td colspan="2">

Reduce peak demand and demand charges
Reduced dependence on fossil fuels for peaking generation, with the consequent reduction in greenhouse gas emission
Avoided T&D and generation capacity and costs
Improved system reliability
Empower customers to manage their energy consumption, bills and provide them opportunity to make energy purchases that meet their individual needs.
Play a critical role in the operation of the truly smart grid.

</td></tr>
</table>

AMI: Advanced Metering Infrastructure
CIS: Customer Information System
CPP: Critical Peak Pricing
DER: Distributed Energy Resources
DLC: Direct Load Control
DMS: Distribution Management System
DR: Demand Response
DRMS: Demand Response Management System
EMS: Energy Management System
HAN: Home Area Network
HEMS: Home Energy Management System
HVAC: Heating, Ventilation, and Air-Conditioning
HW/SW: Hardware / Software
IHDs: In-Home Displays
MDMS: Meter Data Management System
PCTs: Programmable Controllable Thermostats
RTP: Real-Time Pricing
SCADA: Supervisory Control and Data Acquisition
T&D: Transmission & Distribution
TOU: Time-of-Use
WiMAX: Worldwide Interoperability for Microwave Access

Table D-5: Use Case 5 – Distribution Automation

Title:	**Distribution Automation –**Integrated Voltage and Feeder Management Improves Power Quality and Delivery Efficiency and Customer Service Reliability
Application Description:	■ Distribution automation hardware including remote monitoring and sensing technologies, regulators, controllers, advanced relays, recloser controls, faulted circuit indicators (FCIs) and automated switches are deployed throughout the distribution system ■ Reliable two-way DA communication network with low system latency (less than tens of milliseconds) is deployed to support dynamic and integrated VVO/CVR and FLISR functionality ■ Advanced metering infrastructure complements the DA communication network and smart meters provide load/voltage/outage information at customer sites ■ Volt-VAR Control (VVC) controls capacitor banks, load tap changers, and voltage regulators to regulate distribution voltage and minimize VAR flows through distribution lines. ■ Integrated VVC solutions incorporate a centralized voltage optimization algorithm referred as "Conservation Voltage Regulation (CVR)" to either reduce peak load, or minimize system losses by reducing energy consumption ■ Near-real-time current and voltage data acquired via SCADA, AMI, or other remote sensors can be utilized by state estimator and load flow analysis programs of a distribution management system (DMS) to dynamically optimize the voltage profiles for each circuit and the system as a whole in an autonomous fashion. ■ Automated Feeder Management (AFM) applications improve reliability by reconfiguring distribution feeders to optimize transformer loadings, circuit loadings, phase loadings, voltages and also in response to power system faults, overloads, and maintenance needs. ■ Near-real-time outage/current data acquired via SCADA, AMI, or other remote sensors when a fault occurs can be utilized by DMS distribution management system (DMS) to automatically identify the location of the fault, isolate the fault and restore electric service by switching un-faulted line segments to adjacent feeders with free capacity.

Primary Business / Operational Need Addressed	**Business Processes Impacted**
■ Reduce distribution system losses ■ Improve power quality by improving power factor and regulating system voltage to avoid violations ■ Reduce system load (peak and off-peak) ■ Reduce demand charges ■ Improve fault location identification ■ Improves customer service reliability by reducing number of customer outages and outage duration ■ Enables distribution reconfiguration for load balancing between substation transformers or distribution feeders, reducing system losses	■ Distribution and substation operations ■ System maintenance ■ Distribution/line crew dispatch process ■ Distribution peak-load management operations ■ Outage management process ■ Safety procedures ■ System maintenance ■ Distribution crew dispatch process

Hardware/Software Requirements	Communication Requirements
■ Automation hardware (voltage/current sensors and regulators, capacitor banks, LTCs, RTUs, IEDs, PLCs, advanced relays, recloser controls, faulted circuit indicators (FCIs), automated switches) and controllers ■ Master or distributed system software (SCADA/DMS) with VVO/CVR and FLISR functionality to initiate VVO/CVR commands, determine fault location, and then evaluate and produce an optimized restoration solution for non-faulted circuit segments for autonomous functionality. ■ Engineering analysis tools	■ Two-way communication from master station with VVO/CVR and FLISR capability to substation and/or to the field hardware is required ■ Moderate latency and relatively low bandwidth systems can be acceptable for basic VVO/CVR and FLISR functionality ■ Communication system reliability should be high and system latency should be low (tens of milliseconds) for real-time dynamic VVO/CVR and FLISR operations
Technology Challenges	**Business Challenges**
■ Scalability of the vendor system software depending on centralized or distributed DA and control approach ■ Cost/complexity of maintaining additional system hardware may be high ■ Voltage violations may occur at some customer sites ■ Expected peak load reduction may not be achieved due to different types of loads across feeders ■ Inaccurate line impedance data from network model may impact system accuracy	■ Existing equipment like capacitor banks, regulators and LTCs cannot be retrofitted to allow remote monitoring and control ■ System losses can increase for constant power loads ■ Lack of a network model ■ Utility safety procedures may not allow automatic switching; all switching would then fall under an operator's supervision, which may increase restoration times
Utility Interface Requirements	**Training Requirements**
■ If installed as a SCADA Master Software plug-in no other utility system interfaces are required to perform the primary VVO/CVR and basic AFM functions ■ Interface with existing SCADA system if deploying a 3rd party solution (DMS) for integrated VVO/CVR and FLISR functionality ■ Interfaces to GIS, OMS or AMI could improve system accuracy and functionality	■ SCADA technicians need training on programming the relays and re-closer controls, RTUs, and other hardware components ■ Protection engineers require full awareness of AFM capability to implement it correctly ■ Distribution operators should be trained on the master station software with integrated VVO/CVR and FLISR functionality

Benefits & Future Potential:	Benefits to VVO and CVR applications: ■ Reduce energy consumption and distribution system losses ■ Reduce system load (peak and off-peak) ■ Reduce demand charges ■ Reduce carbon footprint ■ Improve power quality by improving power factor and regulating system voltage to avoid violations ■ Eliminate power factor penalties ■ Improve system reliability Benefits of AFM and FLISR applications: ■ Shorter outage duration and fewer sustained outages (reliability performance improvement) ■ Reduce fault investigation time ■ Potential to improve customer satisfaction and minimize economic losses resulting from electrical disruptions ■ Improve the stability of the distribution network under transient conditions (resulting from fault and switching operations).

AFM: Automated Feeder Management
AMI: Advanced Metering Infrastructure
CVR: Conservation Voltage Regulation
DA: Distribution Automation
DMS: Distribution Management System
FCIs: Fault Current Indicators
FLISR: Fault Location, Isolation and Service Restoration
GIS: Geographical Information Systems
HW/SW: Hardware / Software
IEDs: Intelligent Electronic Devices
LTCs: Load Tap Changers
OMS: Outage Management System
PLCs: Programmable Logic Controllers
RTUs: Remote Terminal Units
SCADA: Supervisory Control and Data Acquisition
T&D: Transmission & Distribution
VVC: Volt - VAR Control
VVO: Volt / VAR Optimization

Table D-6: Use Case 6 – Electric Vehicle Charging

<table>
<tr><td>Title:</td><td>Electric Vehicle Charging - Grid Monitoring and Control Enables Wide-scale Electric Vehicle Charging</td></tr>
<tr><td>Application Description:</td><td>

Utilities will be responsible for ensuring that the necessary electrical and two-way communication infrastructure to the Plug-in Electric Vehicle (PEV) charging location and the PEV through AMI/HAN or existing infrastructure are in place.
Utilities will setup the necessary incentive programs, tariffs (such as TOU, CPP, real-time pricing…) to encourage PEV owners to charge during off-peak hours and discharge during emergency, peak-hours when required by the utility or the regional authorities.
Upon proper connection to the electrical outlet, the PEV self-identifies and displays current State of Charge (SOC) of the battery in kW.
Customer shall have the capability to implement a charging event based on a time schedule or rate or a combination thereof. According to the charging event set by the customer, the PEV battery is charged and the total consumption measured by the Utility and the applicable rate information is presented to the customer.
If the customer opted in to participate in demand response (DR) and/or direct load control (DLC) activities, the PEV will be restricted from charging until conclusion of the DR/DLC event. The PEV returns to its normal schedule and settings after an emergency event has concluded
If the customer opted in to participate in a program that allows the Utility to draw charge from the vehicle's battery, the PEV discharges and provides grid quality power when requested by the Utility. The PEV returns to the user prescribed recharging scenario after a discharging event is complete, expired or a restore command is received via the HAN.

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<table>
<tr><th>Primary Business / Operational Need Addressed</th><th>Business Processes Impacted</th></tr>
<tr><td>

Increased availability of PEV charging stations to obtain environmental and societal benefits
To meet state-level greenhouse gas reduction regulatory requirements.
Reduce the net cost of energy for customers
Improve the overall operating efficiency of the utility by allowing the utility to schedule when to deliver a portion of the customers needed energy.
Improve reliability of the grid by participating in DR/load shed activities

</td><td>

System Planning
Distribution Planning
Energy Trading
Customer Service
Distribution peak-load management operations
Rates and Tariffs

</td></tr>
<tr><th>Hardware/Software Requirements</th><th>Communication Requirements</th></tr>
<tr><td>

Necessary electrical infrastructure for PEV charging and discharging
Two-way metering infrastructure
PEV Control and/or Load Management / Demand Response and Management Systems

</td><td>

Two-way communications to PEV
AMI network is one communications option for implementing the PEV interactive link with the utility. However, there are numerous other communications infrastructures that could provide that link such as cellular data networks (4G), broadband networks (wired internet) as well as broadband wireless

</td></tr>
</table>

	networks such as community Wi-Fi and WiMAX. These networks will access the home through a gateway device that provides an interface between those Wide Area Networks and the Home Area Network (HAN) that would be established within the home. The HAN will most likely be wireless but powerline carrier is also an option. Some systems offer both options to facilitate total home coverage
Technology Challenges	**Business Challenges**
▪ There are numerous technical solutions that can provide many of the required functional capabilities required. A strategic view needs to be developed that takes into account all of the potential applications before technologies are chosen.	▪ Some of the benefits of load control may become functional at different times during the life of the initial investment making the business case more complex ▪ Potential for dissatisfaction of PEV owners as they realize the cost involved in the infrastructure changes required to expand the power delivery circuit in the home which may extend beyond the home power distribution panel to the distribution transformer and up
Utility Interface Requirements	**Training Requirements**
▪ Interface with AMI/MDMS, CIS ▪ Interface with Load Management / Demand Response and Management Systems	▪ Technology and Customer Participation

Benefits & Future Potential:	Benefits of PEV: ▪ Reduce peak demand ▪ Reduce demand charges ▪ Reduce carbon footprint ▪ Improve system reliability

AMI: Advanced Metering Infrastructure
CIS: Customer Information System
CPP: Critical Peak Pricing
DLC: Direct Load Control
DR: Demand Response
HAN: Home Area Network
HW/SW: Hardware / Software
kW: Kilowatt
MDMS: Meter Data Management System
PEV: Plug-in Electric Vehicle
RTP: Real-Time Pricing
SOC: State of Charge
TOU: Time-of-Use
WiMAX: Worldwide Interoperability for Microwave Access

Table D-7: Use Case 7 – Asset Management

<table>
<tr><td>Title:</td><td colspan="2">Asset Management - Asset Monitoring Enables Proactive System Planning & Maintenance</td></tr>
<tr><td>Application Description:</td><td colspan="2">■ Asset monitoring and sensing devices including IEDs, data acquisition RTUs, sensors (voltage, current, temperature, PD, moisture, vibration, and so forth), relay and/or recloser controls that have the ability to log oscillograph data are deployed throughout the distribution system
■ Reliable two-way DA communication network with high system latency (minutes) is deployed to support asset monitoring and sensing functionality
■ Advanced metering infrastructure complements the DA communication network and smart meters provide load/voltage/outage information
■ Acquire near real-time operational and condition/status data from system assets via SCADA, AMI, or other remote sensors
■ Conduct engineering analysis (loading, loss, outage, voltage/reliability, fault and so forth,…) using these near real-time data from system assets to make more intelligent decisions about maintenance programs and asset replacement strategies
■ Integrate Condition-Based Maintenance (CBM) applications with remote asset monitoring and sensing technologies especially for critical substation assets such as transformers to automate operational and condition/status data collection and to conduct analysis to help predict incipient faults in the transformers.
■ Conduct near real-time engineering analysis through DMS to dynamically control and optimize management/operation of distribution system assets based on near real-time operational and condition/status data from system assets</td></tr>
<tr><td colspan="2">Primary Business / Operational Need Addressed</td><td>Business Processes Impacted</td></tr>
<tr><td colspan="2">■ Improved capital expenditure plans
■ Reduced system losses
■ Improved system reliability through avoided equipment failures
■ Increased asset life and utilization factor
■ Reduced maintenance and inspection costs</td><td>■ Distribution system planning
■ System maintenance
■ Work and asset management
■ Workforce Management</td></tr>
<tr><td colspan="2">Hardware/Software Requirements</td><td>Communication Requirements</td></tr>
<tr><td colspan="2">■ Engineering analysis tools
■ SCADA/DMS system for distribution system monitoring
■ Monitoring/sensing devices: IEDs, sensors (voltage, current, temperature, PD, moisture, vibration, and so forth)
■ IED, relay, or recloser control have the ability to log oscillograph data for protection analysis
■ Data Acquisition RTUs
■ SCADA Master Station/DMS software with CBM functionality or 3rd party CBM application</td><td>■ Two-way communication between SCADA system and field hardware is required
■ Reliable digital communications from master station to monitoring/sensing devices. Low communication bandwidth with high system latency (minutes) is acceptable for monitoring and sensing applications.
■ A local serial connection is required for most IEDs, relays, and recloser controls to retrieve digital fault data</td></tr>
</table>

Technology Challenges	Business Challenges
■ CBM applications are relatively new technology - some implementation risk associated with the accuracy of the technology ■ Cost/complexity of maintaining additional system hardware may be high ■ Reduces overall technology risk	■ Some existing equipment like capacitor banks, regulators and LTCs cannot be retrofitted to allow remote monitoring and control
Utility Interface Requirements	**Training Requirements**
■ For engineering analysis, interfacing with other utility systems may be required depending on where the analysis capabilities reside (such as energy loss calculations is only offered through a vendor's DMS) ■ Interfaces to SCADA, DMS, GIS, OMS or AMI could improve system analysis accuracy ■ No direct interface with other utility applications other than SCADA is needed for basic CBM functionality ■ Interface with existing SCADA/DMS if deploying a 3rd party CBM application ■ Potential value integrating CBM application with workforce management and asset management systems	■ Ability to download and export historical data into report or trending applications, perform energy loss calculations, download fault data from IED for analysis, and perform system fault analysis utilizing downloaded fault data, from field IEDs, relays, and recloser controls, to verify the correct protective settings are in place. ■ Operation of SCADA/DMS ■ CBM practices and analysis
Benefits & Future Potential:	■ Improve system reliability and performance ■ Reduce losses ■ Reduce O&M spending ■ Maximize asset utilization and life

AMI: Advanced Metering Infrastructure
CBM: Condition-Based Maintenance
DA: Distribution Automation
DMS: Distribution Management System
GIS: Geographical Information Systems
HW/SW: Hardware / Software
IEDs: Intelligent Electronic Devices
LTCs: Load Tap Changers
O&M: Operations & Maintenance
OMS: Outage Management System
PD: Partial Discharge
RTUs: Remote Terminal Units
SCADA: Supervisory Control and Data Acquisition

APPENDIX E: Smart Grid Business Case Framework

The following discussion focuses on the employment related aspects of Smart Grid and is provided to supplement the information contained in Section 5 of the report regarding Smart Grid business case frameworks.

Smart Grid Employment Implications[64]

Implementing a Smart Grid represents an enterprise-wide initiative and impacts the entire utility organization. Smart Grid projects will require a wide range of new skills and education. To meet California's energy policy goals, the implications of Smart Grid will need to be considered, plan for and thus included in the cost-benefit framework developed.

The types of employees needed by Smart Grid employers are as broad as the range of employers themselves. Smart Grid jobs therefore represent a wide variety of educational backgrounds and skill sets, and certainly are not restricted to narrow Smart Grid technical specialties. Relatively few Smart Grid jobs will require deep knowledge of Smart Grid technologies. In fact, most new Smart Grid jobs will draw upon traditional and existing employee skills in business administration, project management, marketing, operations management, finance and accounting, information management and technology. However, as in any industry, Smart Grid employees of all descriptions will need to have a fundamental understanding of the utility industry and of the role of Smart Grid within it.

Jobs created in this industry can be broadly classified into four categories: installation, manufacturing, research and development, and IT services.

The range of Smart Grid jobs may include the following:

- Project management: Project managers, executive assistants, lead consultants
- Program Support: Schedulers, budget analysts, contracts administrators, communications administrators, legal support
- Quality Assurance: Vendor management, test and verification, performance analysts
- Planning: Requirements development, case managers, telecom/communications managers; IT interface (database, software), grid upgrades, rate planning support, marketing & outreach
- Functional Support: Rate design implementation, marketing, public relations, revenue cycle services
- Communications installation management
- IT Software upgrades, replacement, and new applications
- Customer service (such as, call centers)

[64] The U.S. Smart Grid Revolution KEMA's Perspectives for Job Creation, January 13, 2009

- Implementation and Operational Support: Supply chain & inventory management; logistics; meter testing, installation, & disposal; grid component installation (such as transformers, closers, breakers, sensors)
- Functional Specialists: Special metering, outage management, net metering, prepaid services, theft prevention, power management, power quality, asset management, and so forth.

The following list shown in Table E-1, describes the typical position types with either full or part-time job allocations at some level. These positions may already be in-house utility positions that could potentially matrix across and fulfill more than one utility role.

Table E-1: Potential Smart Grid Careers

Smart Grid Position	During Implementation	Steady-State Position
Project Office Leadership		
• Project Manager	X	
• Executive Assistant	X	
• Lead Consultant	X	X
Program Support		
• Scheduler(s)	X	
• Budget Analysis	X	
• Contacts Administrator	X	X
• Resource Manager	X	
• Communication Manager	X	
• Change Management Lead	X	
• Legal Support	X	
Quality Assurance		
• Vendor Management	X	
• Test and Verification Supervisor	X	
• Performance Analysis	X	
Planning		
• Requirements Development Mgr.	X	
• Business Case Manager	X	
• Telecom/Communications	X	
• IT Interface (software, DB)	X	
• Grid Upgrades (such as DA)	X	
• Regulatory Support (rates)	X	
• Marketing Outreach Planning	X	
Functional Support		
• Rate Design Implementation	X	X
• Marketing Implementation	X	
• Public Relations	X	X
• Revenue Cycle Services	X	X
Implementation Operation & Support		
• Supply Chain and Inventory Mgmt.	X	X
• Logistics	X	X
• Meter Receipt Testing	X	X
• Meter Disposal	X	X

Smart Grid Position	During Implementation	Steady-State Position
• Meter Installation (incl. field testing)	X	X
• Grid Component Installation Mgmt.	X	
• Communication Installation Mgmt.	X	X
• IT Software Upgrades, Replacement and New Applications (For Each: Security, CIS, AMI, MDMS, WAM, OMS, DMS/SCADA, DR, DER, Asset Management)	X	X
• Customer Service (Call centers, account managers)	X	X
Functional Specialists		
• Special Metering	X	X
• Outage Management	X	X
• DER & V2G Applications	X	X
• Prepayment Services & Special Billing	X	X
• DR	X	X
• Theft Prevention	X	X
• Field Technical Support	X	X
• DA	X	X
• System Planning & Engineers	X	X
• Asset Management	X	X
• Power Quality	X	X